Design and Simulation of Unified Power Flow Controller with Grid Storage

by

Christopher Beaudoin

A Thesis submitted to the Faculty of Graduate Studies of

The University of Manitoba

in partial fulfilment of the requirements of the degree of

MASTER OF SCIENCE

Department of Electrical and Computer Engineering

University of Manitoba

Winnipeg

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Abstract

Power flow between two transmission systems across an uncontrolled interface can be problematic if there is unequal sharing between the tie lines. System configuration changes such as generation dispatch, or out of service elements can cause thermal overloads. In addition, some weaker areas of the system which may have insufficient transmission can have difficultly supporting the voltage at buses with high loading particularly after the loss of one element.

This thesis presents a real transmission system which has two problems: a thermal limitation caused by unequal tie-sharing across an uncontrolled interface, and a post-fault voltage stability concern. Various potential solutions are analyzed and shown to address one or the other of these two problems; none of which were capable of solving both. A Unified Power Flow Controller (UPFC) is proposed which can effectively address both problems and can provide additional benefit in the form of a grid storage interface.

The operational characteristics of a UPFC are analyzed and used to develop an electrical model and control system topology. The model with its control system is implemented in PSCAD. The UPFC is proven to be capable of effectively addressing the thermal limitation and voltage stability issues of the system. Further, a battery is added to the UPFC to provide grid energy storage. Cost saving measures through controller design are also proposed and implemented.

This work demonstrates that a UPFC can be an effective solution to typical problems (such as thermal and voltage constraints) faced by a transmission system. A UPFC with grid storage can also

provide an alternative to building costly transmission lines or generation by enhancing reliability, reducing demand on generation cause by system peaks, smoothing intermittent generation, etc.

Acknowledgments

I want to thank Dr. Filizadeh who has provide direction and assistance throughout the process of completing this program. Also, I want to thank Manitoba Hydro for providing financial assistance, simulation software, and modeling data, all of which were instrumental for the completion of this program.

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Nomenclature

Symbol	Description
AC	Alternating Current.
BESS	Bulk Energy Storage System.
DC	Direct Current.
FACTS	Flexible Alternating Current Transmission System.
Li-ion	Lithium Ion.
MMC	Modular Multilevel Converter.
OOS	Out Of Service.
PI	Proportional Integral.
PID	Proportional Integral Derivative.
PLL	Phase Locked Loop.
PWM	Pulse Width Modulation.
SLI	Starting, Lighting, and Ignition.
STATCOM	Static synchronous Compensator.
SVC	Static VAr Compensator.
UPFC	Unified Power Flow Controller.

UPS	Uninterruptible Power Supply.
VSC	Voltage Source Converter.

Chapter 1

Introduction

1.1 Motivation

The modern power grid faces a variety of problems. From the perspective of the transmission system the goal is to flow power across the system and this goal is impeded by constraints. When a constraint is reached, no further power can flow which results in potential lost revenue due to inability to sell power, or worse, inability to serve load. These reliability or financial constraints can be solved in many ways including simply building more transmission lines. However, this can be expensive.

The cost to build transmission lines varies but can be around \$400 000 to \$500 000 per kilometer [1]. This means that a line which is only a few kilometers long already costs several million dollars and transmission lines can easily extend to over 100 km. If the transmission line would be longer than about 20 km then Flexible Alternating Current Transmission Systems (FACTS) are similar in cost by comparison while providing a much broader range of benefits [2].

Besides this, utilities will begin to face increasing problems on the generation side as the penetration of intermittent generation increases. The intermittency itself is a major problem because reliance on this type of generation could result in inability to meet peak loading as the generation output fluctuates over the course of a day. Operational difficulties such as managing high ramp rates are also problematic [3]. Adding energy storage to the grid has the potential to mitigate both of these problems by smoothing the generation.

1.2 Objective

The objective of this thesis is to analyze a case study of a transmission system facing constraints typical of the modern power grid and determine potential solutions to these constraints other than building more transmission lines. The transmission system constraints, such as thermal overloading and voltage stability issues, will be understood by modeling the system. Models of the proposed solutions will be analyzed to determine suitability. The most suitable solution will be designed and modeled in detail. The designed solution must resolve all of the constraints. Further enhancement to the design in the form of grid energy storage will be investigated. The results of this thesis can be used to inform utilities seeking to upgrade their infrastructure by providing evidence of suitable alternatives when attempting to address transmission or generation system constraints.

1.3 Methodology and Contribution

This thesis presents an analysis of a detailed PSSE power flow model of the affected transmission system. The specific details are withheld for confidentiality reasons. This model is used to evaluate the steady state operational characteristics of several potential solutions to the constraints. The most suitable of these solutions is designed is detail using PSCAD. Both the electrical and control systems are built from the ground up and evaluated with electromagnetic transient simulation.

This thesis contributes the following:

1. The real transmission system with voltage stability and thermal constraints was introduced and was modeled. A variety of solutions to the constraints were proposed including: switched capacitors, SVC, phase shifting transformer, and UPFC.

2. Analysis of each of the proposed solutions was performed in steady state and most were discarded as inadequate due to only being able to address at most either the voltage stability problem or the thermal limitations but not both.

3. A UPFC is proposed as the solution to the problems faced by the transmission system. The UPFC addresses the thermal limitation by effectively controlling the flow on the transmission line and it addresses the voltage stability issue by providing reactive power support.

4. A mathematical analysis of the control characteristics of a UPFC was performed and a partially decoupled control system was derived from the analysis. The decoupling significantly improves the ability of the controller to respond to disturbances by allowing independent control of active and reactive power.

5. The UPFC electrical and controller components were designed in detail and modeled in PSCAD with the control system from the mathematical analysis. The control system was tuned using an optimization technique.

6. The UPFC system was subjected to a variety of disturbances including fault analysis of the actual transmission system constraint. The control system was shown to perform closely to the expected results based on the mathematical analysis. The UPFC was shown to be capable of addressing the thermal limitation and voltage stability issues of the transmission system.

7. A battery was added to the UPFC and shown to be equally capable of addressing the system issues while also providing the benefit of grid energy storage. Cost saving measures through controller design are also proposed and implemented.

1.4 Overview

Chapter 1: Motivation, Objective, Methodology and Contribution.

Chapter 2: Literature review providing relevant background information on FACTS devices, grid energy storage, and transmission system security analysis.

Chapter 3: Discussion of the problem statement. Presentation of the transmission system to be studied and details of the constraints.

Chapter 4: Evaluation of several proposed solutions: switched capacitors, static VAr compensator, static synchronous compensator, and unified power flow controller.

Chapter 5: Detailed design and dynamic modeling of a unified power flow controller beginning with mathematical analysis and moving into a PSCAD model.

Chapter 6: Evaluation of the performance of the dynamic model by subjecting the controllers to a variety of step response tests and subjecting the completed system to a fault analysis.

Chapter 7: Addition of grid storage to the dynamic model and re-evaluation of its performance by repeating all of the tests previously performed.

Chapter 8: Conclusion with discussion for future work.

Chapter 2

Background and Literature Review

2.1 Flexible Alternating Current Transmission System Devices

Flexible Alternating Current Transmission System (FACTS) devices are a collection of semi-conductor based devices which take advantage of the ability to switch the semi-conductors to provide more flexible control over a transmission system. For example, dynamic levels of reactive power compensation can be provided by switching whereas a typical passive device would only provide static compensation [4].

2.1.1 Static VAr Compensator

Thyristor based devices such as a Static VAr Compensator (SVC) provide variable reactive power injection. This is achieved by connecting a reactor in series with thyristors and placing the result in shunt with the AC bus. Reactive power is modulated by controlling the phase angle at which the reactor is inserted into the system in each cycle. The peak current can be reduced by delaying the phase angle which has the effect of making the reactor appear to be equivalent to a smaller static reactor for a given phase angle delay. The apparent size of the reactor can be reduced in this way however there is no way to increase the apparent size of the reactor. A full range of reactive power compensation (including capacitive) can be accomplished by combining a thyristor switched reactor with a switchable capacitor, sized to match the reactor. To absorb reactive power, the capacitor is switched out and the reactor is operated as described. To provide reactive power, the capacitor is switched in and the reactor is operated as described. In either case the reactor is the component that provides the variability in reactive power output [4].

The major drawback of an SVC is that the switching frequency is near the line frequency and therefore significant low order harmonics are generated. Expensive low frequency harmonic filtering is necessary in order to meet typical transmission system harmonic criteria. Additionally the reactive power capacity of the SVC is proportional to the AC voltage magnitude squared since passive components are used. This means that the capacity of the SVC drops significantly when voltage support is required (i.e. when voltage is low) [4].

2.1.2 Static Synchronous Compensator

A Static Synchronous Compensator (STATCOM) also provides variable reactive power injection similar to an SVC. However, STATCOMs typically use transistor based switches rather than thyristors. A STATCOM consists of a DC capacitor and a Voltage Source Converter (VSC) which is connected to the AC system through a reactance (such as a transformer). The amount of power, both active and reactive, can be directly controlled by modulating the voltage produced at the terminal of the VSC. The details of this exchange are explored in Chapter 5. The active power must be controlled to maintain the DC voltage which in the case of a STATCOM usually means that active power will be consumed to power the system. No active power can be provided unless an additional energy storage device is added to the DC side. This is explored in Chapter 7. Conversely, reactive power can be controlled independently as needed [4].

The switching frequency of the STATCOM can be in the range of kHz. This means that harmonics are typically at a much higher frequency than those of an SVC and therefore do not require as much investment into filtering. However the higher switching frequency also contributes to higher losses (i.e. operational costs). An additional benefit is that power output is directly proportional to AC voltage magnitude rather than a squared relationship. This means that capacity does not reduce as much when reactive power is needed (i.e. when voltage is low) [4].

2.1.3 Unified Power Flow Controller

A Unified Power Flow Controller is composed of two VSCs which share a single DC bus: one VSC in STATCOM configuration, and one connected such that its terminal voltage is injected in series with a transmission line. The series half's injected voltage appears to the system as an impedance in series with the line. The flow on this line can be controlled by varying the apparent impedance of the line. The combined impedance of the transmission line and injected impedance can be increased or decreased as required. Doing so in general may require a resistive component to the injected impedance and as such may consume or supply active power. This power must be cycled through the DC bus by the shunt half of the UPFC. A UPFC can provide voltage support equivalent to a STATCOM while also allowing for control of the flow on a transmission line [4].

Switching for a UPFC is equivalent to a STATCOM and therefore generates high frequency harmonics, allowing for reduced filtering requirements but with higher switching losses. The main drawback is that a UPFC requires approximately double the components compared to a STATCOM and therefore double the cost and complexity. Grid energy storage can also be added to a UPFC through the shared DC bus similarly to a STATCOM [4].

2.2 VSC Switching Control Techniques

There are many ways to control the switching of a VSC. Switching techniques can have varying advantages and disadvantages. For example, some techniques may increase complexity while reducing harmonics or vice versa. This thesis will explore only two of them.

2.2.1 Pulse Width Modulation

Pulse Width Modulation (PWM) is probably the most simple switching technique to implement. Let's suppose there is some desired analog output voltage waveform with an upper bound on frequency content. A two-level VSC can only output either its positive voltage, or its negative voltage but it is possible to create a voltage waveform such that the low frequency content matches the desired signal. This is accomplished by switching according to a comparison between the desired signal and a constant high frequency carrier signal (typically a triangular waveform). The resultant waveform only has two magnitudes where the high level is output if the signal exceeds the carrier and low level is output if the carrier exceeds the signal. This two-level waveform has a lot of high frequency content but the low frequency content matches the desired output. The desired voltage waveform is recovered by using low pass filtering. If the desired waveform is a sinusoid then this technique is called sinusoidal PWM [4].

The major advantage of this technique is the constant switching frequency and the simplicity of implementation but there are some drawbacks. This simple PWM requires the carrier signal to have a much higher frequency than the desired waveform which can contribute to higher switching losses compared to other techniques [4]. Using PWM in this manner can actually complicate the controller although the switching implementation is very simple. This happens when a control parameter is not linear with respect to VSC terminal voltage. Compensating for the non-linearity adds complexity to the controller but neglecting compensation may result in poor controller performance.

2.2.2 Hysteresis Current Control

It is possible to directly create a current signal using a VSC through a control scheme such as Hysteresis Current Control (HCC). This is sometimes desirable when system parameters respond linearly to current instead of voltage. The scheme works as follows. For a two level VSC, the high level usually corresponds to increasing output current and the low level corresponds to decreasing current. Upper and lower bounds are specified around the desired output current waveform. When the output current exits the boundary around the desired waveform (in either direction), then the VSC switches from one switching state to the other, causing a reversal of the current trajectory. The name “hysteresis” comes from the fact that the switching behavior depends not only on the current output but also the initial switching state [5].

The main advantage of HCC is that it is a very simple way to directly achieve current output. Additionally, the precision of the output waveform can be easily controlled by tightening or loosening the boundaries. This comes with a serious drawback. Switching is not tied to any carrier signal as in PWM, and depends on the current output and trajectory. This means that the switching frequency changes as the output magnitude changes as well as for any changes to the AC network. This complicates harmonic generation which is therefore more difficult to adequately filter. HCC also can require a high switching frequency (similar to PWM) which contributes to losses [5].

2.3 Bulk Energy Storage Systems

A power system, or power grid, is a conductive network which distributes electrical energy from sources to consumers. Generators create electricity by converting from some other form of energy such as chemical (coal, natural gas), kinetic (hydraulic, wind), solar, etc. Loads receive the energy from the network and consume it. Two important parameters of the grid are voltage and frequency; typically these are desired to remain constant which necessitates that the energy being produced must exactly match the energy consumed. Otherwise, the parameters will deviate. Energy mismatch will be compensated usually by the spinning masses of generators which changes the frequency. Load is generally uncontrollable by the generator owners and fluctuates considerably. This results in requiring generators which can change their output to match the load. This is complicated by some types of generation which are unable to easily control their output. For example, wind turbines cannot increase their output beyond the available wind power. One solution to this problem is to store energy when there is excess generation available and use it when there is excess load. This is referred to as grid storage.

To some extent there is already significant energy storage in the power grid as most generators have a rotating mass which stores kinetic energy. During system disturbances, the energy stored in the rotating mass can be relied upon for system stability. This is referred to as system inertia. Generally these masses cannot be relied upon for energy since most generators are synchronous and changes in the kinetic energy of the mass directly result in changes to the frequency of the generated voltage, which is not desirable. Additionally most generators are not designed to provide energy in the absence of fuel (or wind, or water), nor to convert excess energy back into fuel. The ability to bidirectionally convert between fuel and energy is what separates conventional generation from energy storage.

At its most basic level an energy storage system requires two components: a “fuel” source, and a bidirectional interface. The “fuel” can be any substance, or mode of a substance, from which energy can be extracted and returned. This includes reversible chemical reactions, pressurized gases, pumped fluids, rotating masses, combustible materials, etc. In the case of combustible materials, the material must be synthesizable on site without requiring additional consumable ingredients. The interface must be bidirectional. If the direction is only from fuel to energy then it is no different than a conventional generator. If the direction is only from energy to fuel then it is merely a fuel factory, which from the grid’s perspective is just another load.

2.4 Interfacing

Energy storage systems can be interfaced with the grid in two ways: synchronous, or asynchronous. It is always possible to interface asynchronously however some types of storage may also be interfaced synchronously. The choice between the two depends largely on the method of energy extraction from the fuel. Generally if the extraction is done by causing something to rotate, then the interface can be synchronous. Of the previously mentioned types of fuel, this includes: pressurized gases, pumped fluids, and combustible materials. If the extraction is done without causing something to rotate then the method must be asynchronous. Of the previously mentioned types of fuel, this includes: reversible chemical reactions, and rotating masses (i.e. the rotation of the mass is the "fuel"). Note that rotating masses must be interfaced asynchronously since energy extraction necessarily changes the speed at which the mass rotates.

2.4.1 Synchronous Interfacing

Synchronous interfacing is a very mature technology. Most generation is synchronously connected and has been for much of the history of the power grid. While supplying energy, a storage system connected in this manner appears to the grid to be no different than any other synchronous generator. This type of storage system typically has a governor, an exciter, and a rotating mass. As a consequence, the active power output of the generator tends to be somewhat slower to respond to disturbances due to the need to physically move a governor. The reactive power response depends on the exciter and can be relatively fast if required. While storing energy, the storage system typically appears as a motor load (e.g. a pump). The exception to this might be reversible combustion type storage for which it depends on how the fuel is being synthesized.

2.4.2 Asynchronous Interfacing

Asynchronous interfacing is a commercially newer technology by comparison to synchronous interfacing. This type of interfacing requires active components, most recently consisting of solid state power electronics. The storage medium produces either zero Hz or varying frequency voltages and must be converting to the grid frequency. There is no rotating mass connected to the grid and therefore no inertia, however pseudo-inertia is achievable through control techniques. This is discussed in more detail in section 2.5.2. Since the interface is solid state and nothing has to physically move, both the active and reactive power responses are very fast and easily controllable. The storage system can appear to the grid as either a load or generator by either storing or supplying energy, and can dynamically adjust if required. The technology involved in this type of interface is still maturing and there are likely still advances to be made.

2.5 State of Grid Storage

Grid energy storage devices can be used for several purposes beyond simply storing excess generation such as: backup power, load leveling, frequency regulation, voltage support, etc [6].

2.5.1 Load Leveling

Load leveling (also peak shaving) is any process which has as its goal to smooth the consumption profile of a load. This can be accomplished either through generation or energy storage. This is typically done to take advantage of price differences at different times of day. In a generation application, the load simply runs its generation during peak times to offset its consumption. In a storage type application, energy is purchased during off-peak times when prices and load are low, then the energy is released during peak times to compensate the load when prices are high [7]. At utility scale, load leveling has several benefits. The power grid must be built to accommodate the peak demand, however the peak demand only occurs for a small portion of the time. This means that infrastructure and expensive peak generation must be built to accommodate this peak loading. Load leveling can reduce both capital and operating costs associated with peak load. The need for peaking generation can be reduced by storing cheaper base load generation during off-peak and releasing the energy at peak time. In the same way, the build requirement for transmission or distribution lines can be reduced by mitigating peak flows through storage during off peak times [8][9].

2.5.2 Frequency Regulation

The frequency of the power grid is controlled primarily through the governor action of conventional rotating mass generation. The rotating mass of the generators acts as a flywheel to feed or consume any energy mismatch at the cost of maintaining rotational speed. Since most generators are synchronous, the change in speed is observable on the grid. The governor action adjusts the mechanical power (e.g. amount of fuel flowing to combustion turbine, amount of water flowing through hydro turbine, etc.) to compensate the energy mismatch. This action is slow, taking time on the order of several seconds. However this is acceptable due to the enormous combined inertia of all the generators on the grid which does not allow the frequency to change quickly [10].

Some forms of energy storage, such as pumped hydro or compressed air, will have a rotating mass with a governor and therefore have the equivalent response time to rotating mass generators for frequency regulation. However, other types of storage such as battery or flywheel have very fast response times on the order of a few milliseconds [6]. The increased penetration of generation sources with no inertia (such as solar and wind) has had a detrimental impact on the frequency response of the grid. Dispatch of these types of generation often replaces dispatch of traditional rotating mass generation, thereby reducing system inertia [11] [12]. Energy storage allows for control techniques which create a pseudo inertia and can be used both to lessen the rate of change of frequency during disturbances or to increase damping of oscillatory modes. As such, frequency regulation as it applies to energy storage will become increasingly important with increasing penetration of low inertia generation [12].

2.5.3 Voltage Support

Conventional generators are the primary method of voltage support in a power grid. Generators supply active power and can either supply or consume reactive power as necessary to control the voltage. Secondary methods of voltage regulation include simple passive reactive devices such as reactors and capacitors. Alternatively controllable reactive devices such as Static Var Compensators or SVCs are also available. Some energy types such as battery or flywheel which are connected to the grid through power electronics can regulate voltage in the same way as an SVC. Energy storage types such as pumped hydro and compressed air are similar to conventional generators and therefore can participate in the same manner as those types of generation. However energy storage has additional ability to participate in voltage regulation since it is able to act as both a load and a generator.

2.6 Power System Security

Power system security refers to the ability of a power system to operate reliably. Disturbances frequently occur to the power system and can be caused by a variety of factors; they are often weather or human error related for example. Generally the disturbance is a fault which is followed by the loss of an element such as a generator, transmission line, or transformer. Operating criteria specify safe limits of operation in order to maintain reliability. The operating criteria typically falls into three time frames each of which may have different criteria to meet: pre-disturbance (steady state), transient (typically a few seconds during and following the disturbance), and post-disturbance (after the transient response of the system has settled). A power system is called "secure" if it is capable of continuing to operate within acceptable operating criteria before, during, and after a disturbance [13].

Operating criteria may be applied to any measurable system parameter; the most common type of limits are applied to voltage and current. Limits on current are typically related to thermal capability, do not have a lower bound, and generally only apply before the disturbance (pre-disturbance) and after the disturbance has settled (post-disturbance) but not during the transient portion of the disturbance. Current based limits are usually intended to prevent overheating. Pre-disturbance and post-disturbance limits may be different. Often the post-disturbance limit is less restrictive and may allow for a short duration overload.

Voltage limits will have both an upper and lower limit, apply to all time frames, and can be applied differently in each time frame. For example a pre-disturbance voltage limit may be more restrictive than a post-disturbance limit. Transient voltage limits can either be a static limit or take the form of a time dependent voltage envelope. The upper limit is intended to prevent damage to equipment insulation and the lower limit is intended to maintain system stability. The voltage must be operated between the two limits at all times. Violating any limit places the system or its components at risk. There is generally no prescriptive way to determine limits and engineering judgment must be used. Some typical voltage limits are: 0.95 pu to 1.05 pu in pre-disturbance, 0.70 pu to 1.3 pu during the disturbance, and 0.90 pu to 1.10 pu in post-disturbance.

A security assessment is the process by which a power system is determined to be secure or not. In the process, a model of the system which contains all relevant components and ratings is subjected to a variety of disturbances. Sometimes only a small area of interest within a larger power system is tested for security. Often the list of disturbances will include only those that are relevant to the area of interest. The system (or subsystem) is secure if the model shows that no operating criteria will be violated for any of the disturbances [13].

2.7 Transfer Capability

An "interface" is defined as the set of elements that interconnects two parts of a power system. Often an interface is selected where transfer of active power is desired and is potentially restricted by one or more elements that make up the interface. The "transfer capability" of the interface is defined to be the maximum amount of active power that can flow across the interface while maintaining system security as determined by a security assessment (see section 2.6). The transfer capability is determined using the following procedure:

1. Select a known secure starting transfer level,
2. Increment the transfer level, perform any necessary system posturing, and perform a security assessment,
3. If the system is secure then return to step 2, otherwise proceed,
4. The transfer capability of the interface is determined to be the last secure level found in step 3.

This procedure will find the transfer capability to within a margin determined by the size of the increment chosen in step 2. Sometimes a transfer capability is dependent on some external variable. In this case the procedure must be repeated across the range of the external variable in order to find the dependency.

One objective of the power system owner is to maximize the amount of active power that can be transferred from system A to system B. Line 3 is the highest rated line and thus typically carries most of the power. However from time to time Line 3 is removed from service due to faults or maintenance. During these times, the transfer capability from system A to system B is extremely restricted and is limited by the rating of Line 2. This is not the only circumstance in which Line 2 is the most limiting element however it will serve as an excellent example for which to evaluate the effectiveness of a solution which addresses transfer capability.

Chapter 3

Problem Statement

3.1 Overview

Figure 3.1 shows a system schematic of the area of interest. This is a representation of a real transmission system which has been given generic names in order to hide the identity of the owner. System A and System B are two large interconnected AC power grids which are tied by high voltage transmission lines: Line 1, Line 2, Line 3, Line 4, and Line 5. An Additional surrounding network also connects these two systems and is represented by Line 6 in the schematic. It is difficult to estimate the effective impedance of the surrounding network (Line 6) due to the complicated interactions between various elements of the power system. Power and voltage control devices such as switchable shunt reactive elements, DC lines, and phase shifting transformers create non-linear relationships to power flow. The impedance shown in the schematic is simply an estimate to provide context against the other lines.

The estimate of impedance for Line 6 was determined as follows. The system-intact power system model was used to create four prior-outage cases, each with one of the lines 2 through 5 removed from service. An impedance multiplier was determined in each case by comparing the amount of power that shifted to Line 6 with one transmission line out of service. Power transfer is defined in equation 3.1. The impedance multiplier is defined in equation 3.2 where OOS stands for Out Of Service.

$$\text{transfer} = \sum_{n=2}^{5} line\_n_{active\_power} \tag{3.1}$$

$$multiplier_n = \frac{transfer_{line\_n\_OOS}}{transfer_{system\_intact} - transfer_{line\_n\_OOS}} \tag{3.2}$$

An estimate for the impedance of Line 6 is determined from the product of the multiplier from equation 3.2 and the effective impedance of the remaining in-service parallel lines. Note that lines 2 through 5 are not directly in parallel and the power system is non-linear therefore this method produces an approximate impedance for context only. The smallest impedance found for Line 6 using this method was for Line 3 out of service and is shown in the schematic.

The system owner has several requirements for this region: to maximize the active power transfer capability from System A to System B, and to ensure that the load is served at Bus 1.

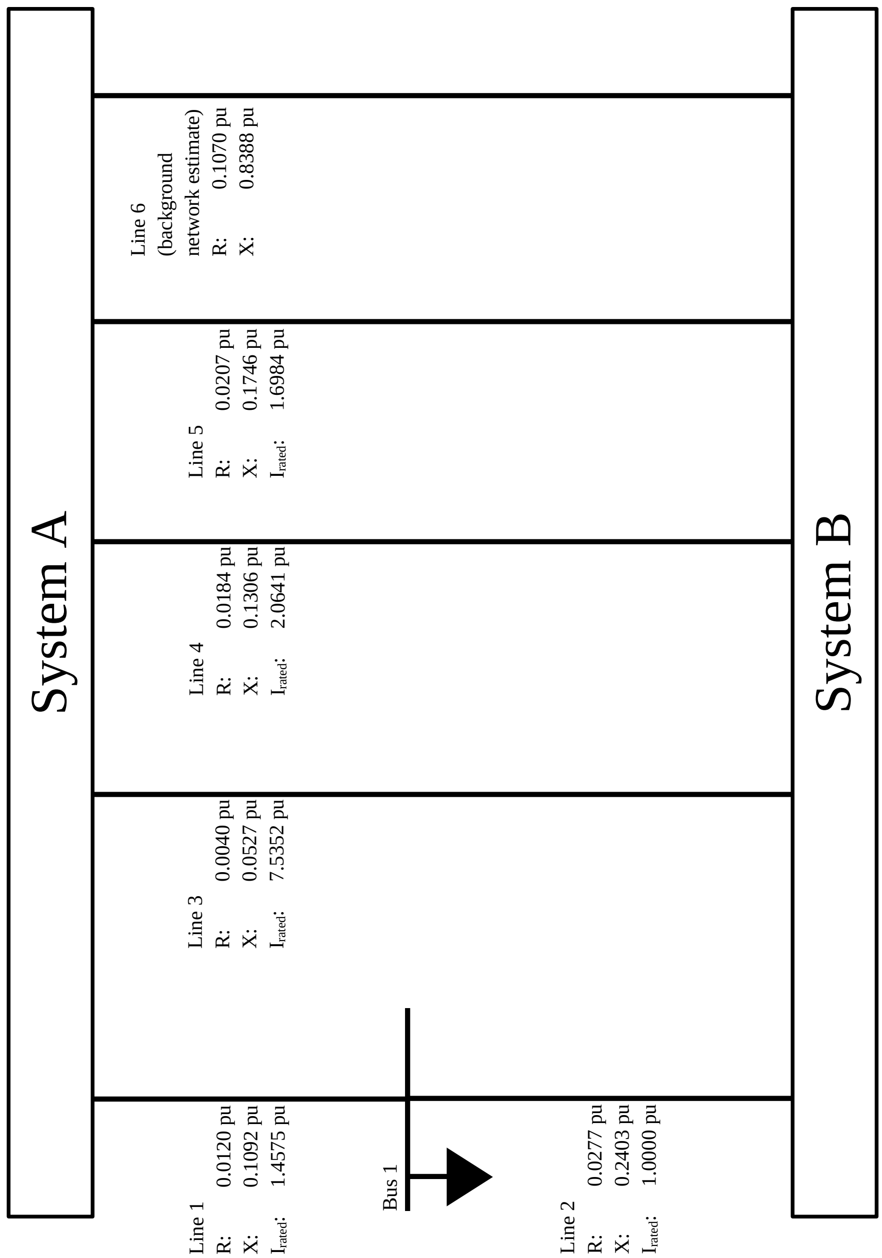

Fig. 3.1: System overview

3.2 Voltage Stability

One objective of the system owner is to ensure that load buses are secure. This means that the system owner wants to continue serving load at all buses even after the loss of one transmission element. Referring to the system diagram in Figure 3.1, Bus 1 is served by two transmission lines: Line 1 from system A, and Line 2 from system B. The source through Line 1 from system A is relatively strong and the load at Bus 1 can easily be supplied for the loss of Line 2; however the reverse is not true. The connection to Bus 1 through Line 2 from system B is weak and the load is sometimes at risk due to low voltage after the loss of Line 1.

The load level which can no longer be served at Bus 1 for loss of Line 1 can be empirically determined using a power flow model and solver such as Siemens' PSSE. It is likely that a system is stable when PSSE can solve the corresponding network (neglecting small signal instability). There are a variety of reasons that PSSE is unable to find a solution. However if a stable network becomes unstable by manipulating a single parameter, then the instability can be reasonably attributed to that parameter.

In this case a voltage stability limit will be estimated by increasing the load at a single bus. When the solver fails to solve after an incremental change to the load at Bus 1, then the last stable load level will be called the load stability limit. Although the inability to obtain a solution from the model is not directly indicative of the stability limit, it provides a reasonable estimate of where the stability limit might be. Additionally, the stability limit search procedure can be repeated after modeling some corrective action and the efficacy of the correction can be estimated. The corrective active can be called successful if there is a significant increase in the stability limit.

Figure 3.2 shows some partial PV curves where P is the load at Bus 1 and V is the voltage at Bus 1 after Line 1 has been removed from service (i.e. serving Bus 1 load from system B). These curves were empirically determined using a detailed system power flow model. Line 1 was removed from service and the load at Bus 1 was increased incrementally until PSSE could not solve the

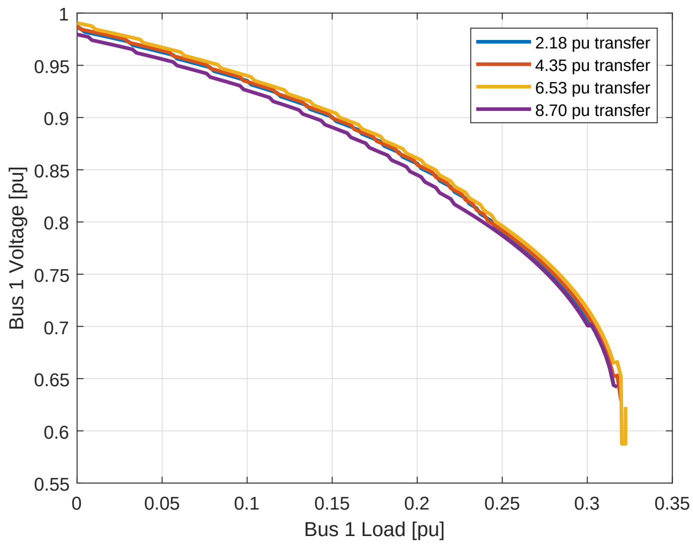

Fig. 3.2: Bus 1 PV curves

network. The test was performed at a variety of active power transfers from system A to system B to determine if there is any relationship between the transfer level and the stability level.

Examination of the figure gives 0.32 pu loading as the approximate stability limit regardless of transfer level. What this means is that Bus 1 loading cannot be called secure for any loading above 0.32 pu; if a Line 1 contingency were to occur, then the voltage at Bus 1 would collapse. Additionally, the post-contingency low voltage criteria is 0.9 pu as set by the system owner. This limit is set both to protect the transmission system from collapse as well as to protect both utility and customer equipment from damage to low voltage. This means that if the voltage at Bus 1 would fall below the criteria for some contingency, then that system configuration is not secure. Load shed is the only possible corrective action given the currently available equipment in the area. There is a risk to the customer, but also to the system since this is a voltage stability issue and the problem might spread to the larger system if left unchecked.

A cumulative load duration curve uses historical data to show the time duration that a load is at or below some level. This type of chart is useful for assessing the severity of a load related

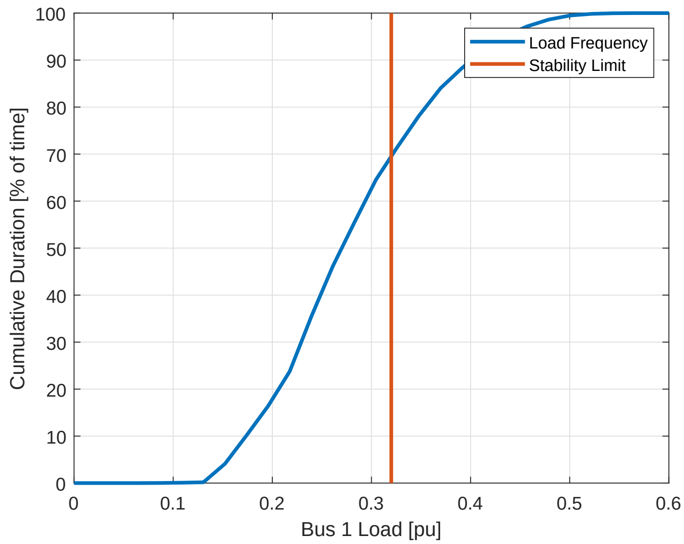

Fig. 3.3: Bus 1 load duration curve

problem since the amount of time that the problem is present can be determined. Figure 3.3 shows the load duration curve for Bus 1 using historical data from 2018. For example, the minimum Bus 1 load approximately 0.13 pu during 2018. This is determined by looking at where the curve first rises above the horizontal axis. Similarly, the bus load level never exceeded 0.52 pu since this is where the curve reaches the top of the chart. The stability limit taken from Figure 3.2 is shown as a red line on Figure 3.3.

Bus 1 was loaded at or below the stability limit of 0.32 pu for approximately 70% of 2018. This means that Bus 1 presented a potential stability concern for 30% of 2018. Furthermore, the post-contingency voltage criteria (0.9 pu voltage) is violated around 0.15 pu loading which means that Bus 1 was not secure due to low voltage criteria for more than 90% of 2018. This issue was addressed by the system owner through load transfers and using planned load shed.

Shedding load is obviously undesirable because this results in customers losing power. Load transfers are also undesired because they typically require manpower to perform (which means they are slow and operationally expensive) and while they mitigate the concern at Bus 1, it comes at the cost of burdening other system buses (not shown in system schematic).

3.3 Summary

In this chapter, a transmission system with constraints is presented. Details of the voltage stability constraint and its relationship to load level were explored.

Chapter 4

Proposed Solutions

4.1 Reactive Power Injection

The voltage stability issue at Bus 1 may be sensitive to nearby reactive power injection. This can easily be tested using the power flow model by injecting reactive power at Bus 1 and measuring the voltage at some given operating point. If the relationship is strong then reactive power injection is a viable solution to fix the voltage stability issue. There are many ways to implement reactive power injection.

4.1.1 Capacitors

The simplest option to inject reactive power into the grid is by using capacitors. The capacitor generates reactive power proportionally to the voltage squared and does not require any active power (conductor losses aside). The squared relationship to voltage is problematic when using capacitors to support voltage since when the voltage is low, the reactive power generating capability of the capacitor is much lower. Conversely, when the capacitor is in service and the voltage is tending upwards, it will generate more reactive power and thus exacerbate the voltage trend. Despite

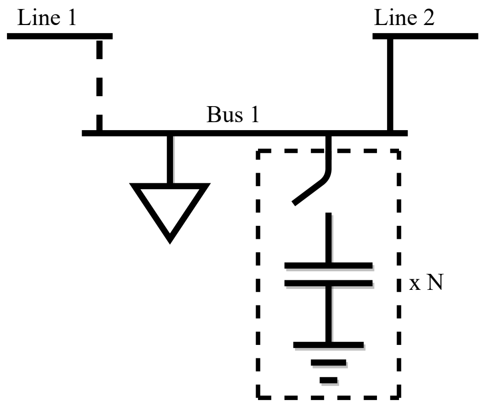

Fig. 4.1: Schematic of switched capacitor banks at Bus 1 as modeled

this, capacitors can be an attractive solution to a utility when only basic controls are required since this is the lowest cost solution to provide reactive power. Capacitor banks can either be controlled manually or automatically however typically they have almost no ability to provide transient voltage benefits. Fast switching capacitors are available which can switch quickly enough to prevent transient drops in voltage but their benefit is limited to that. Transient controls related to damping are not possible. In addition, capacitor banks must be switched in blocks which means that reactive power can only be provided in discrete steps. Theoretically the steps can be made very small, however in practice this does not work due to the increased cost of switches and controls in comparison to the benefit gained with smaller steps.

- **Power Flow Model Implementation**

A detailed power flow based model was available for study. This model contains detailed steady state models of the transmission systems in System A and System B as well as all of the surrounding transmission systems and some of the more significant distribution systems. The model cannot be disclosed due to the confidentiality agreements. A shunt capacitor was inserted at Bus 1 exactly as shown in Figure 4.1. Note that the dotted line between Bus 1 and Line 1 represents an open branch. This means that Bus 1 load is being fed radially by Line 2 which is the system configuration of interest. The capacitor was sized with varying numbers of banks available; each bank was sized to 0.1 pu. Note that this size is arbitrary and was simply selected at a reasonable and convenient level consistent with other similar capacitors in the system.

The power flow model is not capable of simulating dynamic performance however in this case that is not necessary. Instead, the control characteristic of the capacitor with respect to the voltage can be determined by varying a model parameter by a small amount and then solving the model. The capacitor banks were not modeled with any control system however in each step the capacitors were controlled in a manner that would be consistent with how a human operator would control the devices. In practice there would be some hysteretical effects however those are not of interest to this study and were not considered.

A simple test procedure can be used to experimentally determine the effectiveness of a fixed capacitor based solution. This procedure models how human system operators would control manually switched capacitors:

1. Place a switchable capacitor with some number of blocks at Bus 1,
2. Increment the load at Bus 1 until one of the following:
    (a) If the voltage at Bus 1 drops below 0.9 pu and a capacitor bank is available, then switch in a capacitor bank and return to step 2
    (b) Else if the model does not solve then stop

- **Analysis**

Figure 4.2 shows PV curves between load at Bus 1 and voltage at Bus 1 for a Line 1 contingency which were generated using the test procedure. The number of available capacitor banks was varied and is shown in the legend. The step changes in voltage that appear in the figure are the load levels at which additional banks were required. The "0 cap banks" curve is the same curve as shown in Figure 3.2 since this is the case where there are no capacitor banks available. Additional numbers

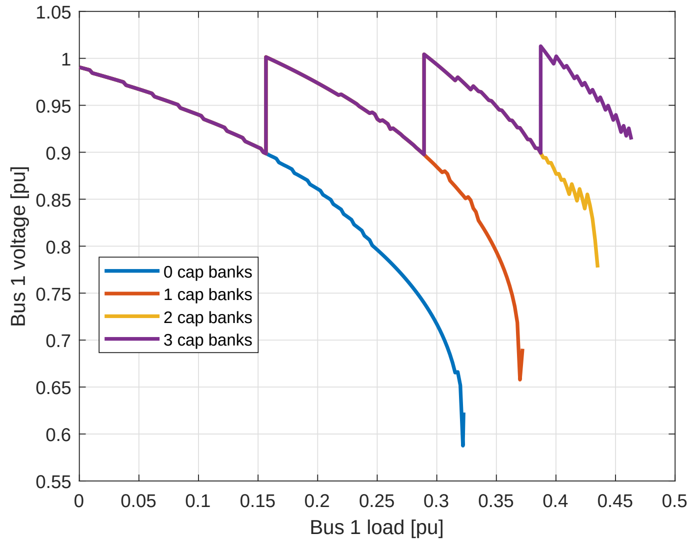

Fig. 4.2: Switched capacitor banks - PV curves

of available capacitor banks beyond 3 were simulated however it was found that the model would stop solving before the 4th capacitor bank was required. Inspection of Figure 4.2 shows that adding capacitor banks to Bus 1 would allow an increase in the stability limit up to approximately 0.45 pu load. At this point the system becomes very unstable and the model is unable to solve even when additional capacitor banks could be available.

By comparing the new stability limit against the load duration curve in Figure 3.3, it can be seen that the increase in stability limit is insufficient to cover all expected load levels. The loading at Bus 1 is below 0.45 pu approximately 95% of the time. This leaves 5% of the time where either the system may be insecure, or load shedding may be required. It is possible that reducing the size of individual capacitor blocks and having more blocks could extend the voltage stability beyond 0.45 pu; however this adds additional cost due to the extra switches and controls. Doing so would move the system closer to a continuously controllable system.

4.1.2 Continuously Controllable Reactive Power Injection

There is more than one way to generate reactive power with continuous control. This section will describe two possible devices which can both meet the requirement: Static VAr Compensator, and Static Synchronous Compensator [14]. In a steady state power flow analysis, these two devices appear to the system to be identical; therefore the analysis of one of them applies to both of them and will appear at the end of this section. Note that the transient behavior of these devices is quite different from each other and would require separate simulations for analysis.

- **Static VAr Compensator**

A Static VAr Compensator, or SVC, is a power electronics based device which can provide reactive power support to the grid. A very simple SVC connected to Bus 1 is shown in Figure 4.3. It consists of a capacitor and an inductor which are both individually switched with thyristors. In the design shown in the figure, the capacitor provides reactive power and the inductor can absorb reactive power which gives this device two modes of operation. In some cases the capacitor is not switched via thyristor and instead is switched with a mechanical switch. In either case the inductor is required in all modes of operation in order to provide continuous control when generating reactive power since a switched capacitor is only discretely controllable. The advantage of switching the capacitor with thyristors is enhanced speed of control of the capacitors. Mechanical switches could only react to slowly varying system conditions. An SVC requires a power supply to perform switching and thus consumes active power while operating. SVC switching is on the same order of magnitude as the system frequency and thus generates significant low order harmonics. Harmonic filtering is likely required (not shown in the figure), increasing both the cost and footprint of the device.

An SVC in steady state effectively switches the reactive elements in such a way that they generate reactive power equivalent to a smaller static element. Thus the elements of an SVC appear to the grid to be of varying size; however only smaller sizes are possible. For example, this

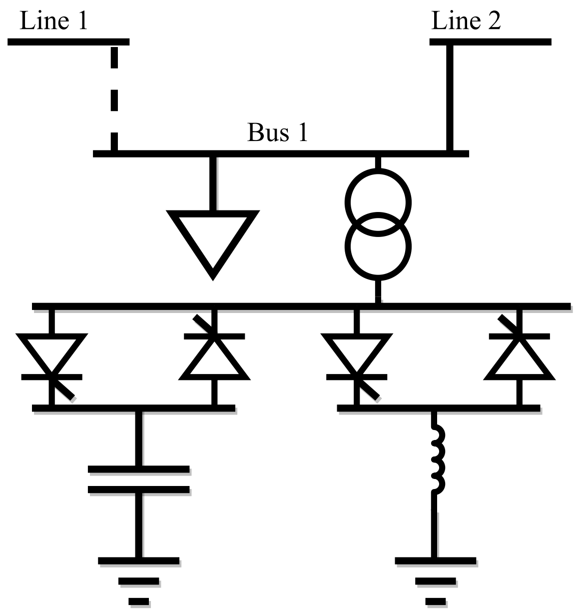

Fig. 4.3: Schematic of an SVC at Bus 1

means that the SVC is not capable of generating more reactive power than the capacitor would have been able to had it simply been a static capacitor. The maximum operating point of the SVC is the same as the corresponding passive device (inductor or capacitor), had it been directly connected to the grid. Since the SVC is just switching reactive devices, the squared voltage relationship still remains. This is again problematic when voltage support is required since the reactive power generating capability is reduced when it is needed most. However, an SVC provides an advantage over a static capacitor when the voltage is high because it can switch its elements to provide less reactive power.

The main benefit of an SVC over a simple capacitor is the ability to inject reactive power across a continuous range (not just discrete values) and thus have better control over bus voltages. The SVC allows for continuously variable output to meet the exact reactive power requirement. In addition, SVCs can react quickly to transient conditions and can provide benefits such as damping and transient voltage stability. The disadvantage compared to a simple capacitor is cost and footprint. An SVC is much more expensive than fixed capacitors, it has a larger footprint (i.e. occupies more physical space), and has a higher operating cost (both maintenance and flactive power consumption). A utility may choose to incur the additional expense and build an SVC when transient voltage support is required since a simple capacitor can not provide this.

- **Static Synchronous Compensator**

A Static synchronous Compensator, STATCOM, is also a power-electronics based device which can provide reactive power support to the grid. It consists of a voltage source converter (VSC) represented by the block with a diode and a DC capacitor. A simple schematic of a STATCOM connected to Bus 1 is shown in Figure 4.4. The capacitor maintains a constant DC voltage which is used by the VSC to generate an AC voltage in order to transmit reactive power. It functions very similarly to an SVC in that it can provide reactive power to the grid in two modes of operation. It can either generate or absorb reactive power; however the capacity of the STATCOM is directly proportional to the terminal voltage. This is major advantage when compared to an SVC which has a squared relationship to the voltage. This means that when reactive power generation is required, the STATCOM's capability is not reduced to the extent that an SVC's capability would be.

An SVC is capable of generating or consuming only reactive power; the same is not true of a STATCOM. A battery-based energy storage device typically uses an AC voltage source which is converted to DC to charge the batteries. It is also capable of turning the DC back into AC to discharge the batteries. If the device which is used to do this is a voltage source converter then it is effectively a STATCOM with energy storage. The addition of energy storage is optional and is not required for a STATCOM. However a device with energy storage would be capable of four modes of operation since it could generate or consume both active and reactive power. For the analysis performed in this section, only the reactive modes of operation will be considered. The active modes of operation will be discussed in future sections.

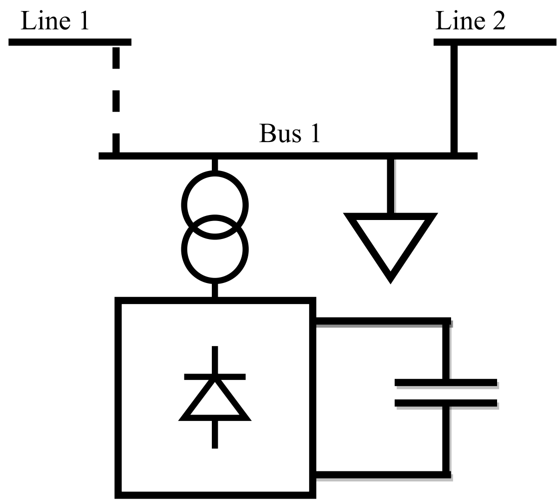

Fig. 4.4: Schematic of a STATCOM at Bus 1

A STATCOM should be switched at least at a switching frequency on the order of 1 kHz (at least ten times the grid frequency). This reduces the filtering requirement by comparison to an SVC. The footprint requirement of a STATCOM is comparable to an SVC however the reduced filtering allows for a slightly smaller footprint for the STATCOM. A STATCOM also has comparable requirements to an SVC for operating costs (maintenance and active power consumption).

- **Analysis of SVC and STATCOM in Steady State**

From a steady state perspective, both the SVC and the STATCOM inject reactive power into the grid in the same way. This impact can be easily simulated using a detailed power flow model. The same model was used as that which was used in section 4.1.1 to perform the analysis of the simple capacitor solution. A shunt reactive device with continuous control and a voltage set point was inserted at Bus 1 instead of a static shunt device with blocks. This is shown in Figure 4.5. Note that the figure shows the label "SVC" however the same variable shunt reactive model is representative of a STATCOM in steady state. An SVC or STATCOM would require a control system with some dynamic characteristic, however the dynamics of such a system cannot be modeled in a power flow

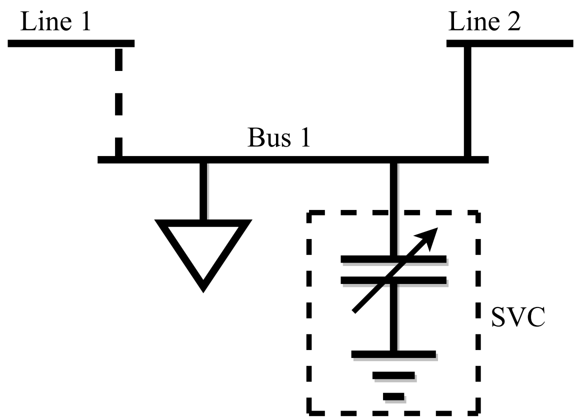

Fig. 4.5: Schematic of the SVC as modeled

model. Therefore it is only possible to consider steady state performance of the control system. For this study the control system is assumed to bring the voltage to 1 pu in steady state. A similar test procedure can be used to determine the steady state control characteristic as in the simple capacitor case:

1. Place an infinite variable capacitor at Bus 1 with voltage set-point at 1 pu
2. Increment the load at Bus 1 until the model no longer solves

Figures 4.6 and 4.7 were generated using this procedure and show the impact of an SVC at Bus 1 for a Line 1 contingency. Each point on these plots was obtained by setting the load, solving the power flow, and measuring the required reactive power injection. Putting all of the points together forms the lines shown in each of the plots. Figure 4.6 shows a PV curve of voltage at Bus 1 vs the load at Bus 1. Since the SVC is infinite, this PV curve is trivially just a straight line with the voltage held at 1.0 pu for all load levels. The figure does indicate that an infinite SVC could extend the voltage stability limit up to approximately 1.0 pu loading. This is more than enough to cover the historical peak load of approximately 0.52 pu. No other information can be obtained from the figure.

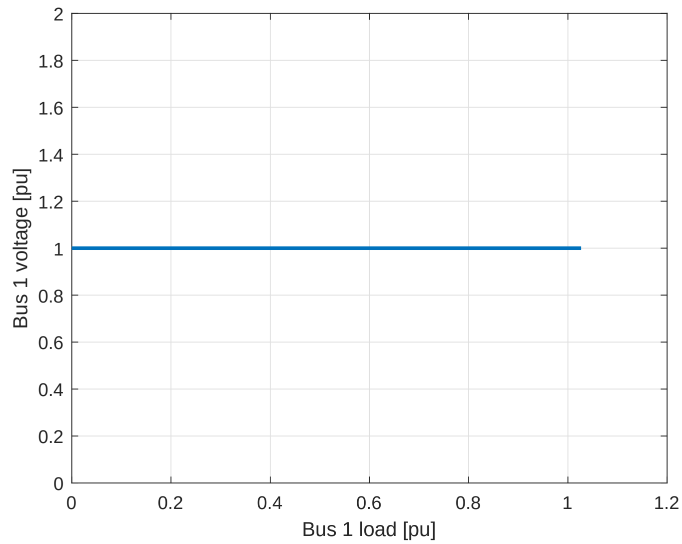

Fig. 4.6: Infinite SVC PV curve

Figure 4.7 shows a PQ curve of the SVC output vs the load at Bus 1. This figure is much more informative since it is the steady state control characteristic of an infinite SVC at Bus 1. It demonstrates the VAr requirement for each load level. This information can be used to determine the sizing requirement of an SVC. For example the required size for an SVC to ensure stability up to the historical peak load is approximately 0.3 pu. This means that either an SVC or a STATCOM of sufficient size is capable of resolving the voltage stability issue up to and beyond historical peak loading.

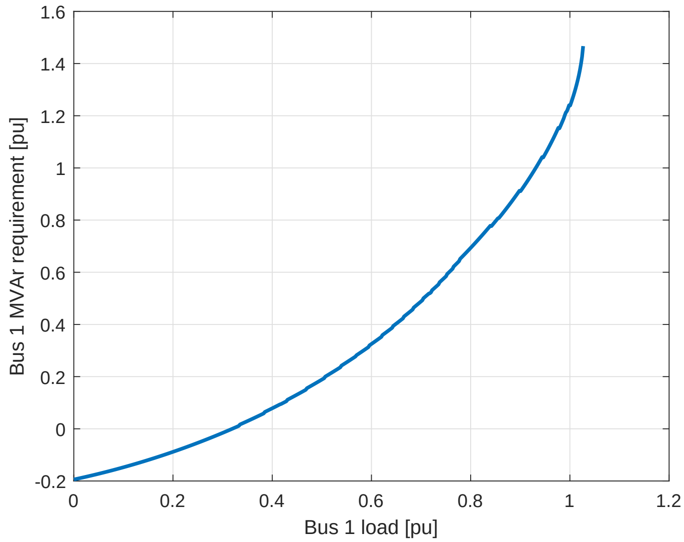

Fig. 4.7: Infinite SVC PQ curve

4.1.3 Transfer Capability Sensitivity to VAr Injection

Up to this point, voltage stability has been the main focus of the problem. From the results demonstrated so far, it is clear that a simple capacitor based solution is insufficient to resolve the voltage stability problem however a properly sized SVC or STATCOM based solution is sufficient. The transfer capability issue must now be discussed.

Of the devices discussed so far, a STATCOM with energy storage will be the first device considered for the transfer capability problem. This is because it has the most capability of any of the devices since it has four modes of operation. The transfer capability problem requires a slightly different model than for the voltage stability problem. In the voltage stability problem analysis, a model with Line 1 out of service was used since this is when the problem manifests. However with Line 1 out of service, Bus 1 becomes a radially fed load from system B and thus no transfer is possible. Instead the system configuration of interest is when Line 1 is in service and Line 3 is out of service. This system configuration will be used for the analysis. The same shunt reactive

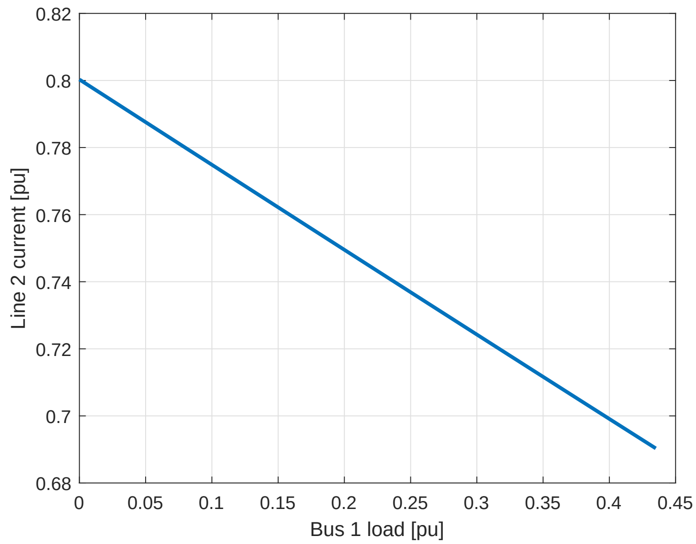

Fig. 4.8: Line 2 flow vs Bus 1 load characteristic

device as for the STATCOM analysis is used again (see Figure 4.5). The difference for this analysis is that the load at Bus 1 is modulated to model energy storage. At this stage, the energy capacity of the device is not considered.

Considering a STATCOM with energy storage, there are two parameters at Bus 1 which can be controlled in order to influence the flow on Line 2. Either reactive power injection or active power injection are possible. Active power injection can be used to make the load at Bus 1 appear either smaller or larger as required. Figure 4.8 shows the control characteristic of load changes at Bus 1 to the flow on Line 2. Each point on the line is obtained by setting the load at Bus 1 and solving the power flow, then measuring the current flow on Line 2. The approximate sensitivity obtained from the plot is -0.25. This is relatively small since it would take a variation in load of almost the entire historical range just to influence the flow on the line by 0.1 pu. Given that the rating of the line is 1.0 pu this is not a viable control parameter.

Reactive power injection can be used for voltage magnitude control. Figure 4.9 shows the control characteristic of the voltage magnitude at Bus 1 to flow on Line 2. Each point on the

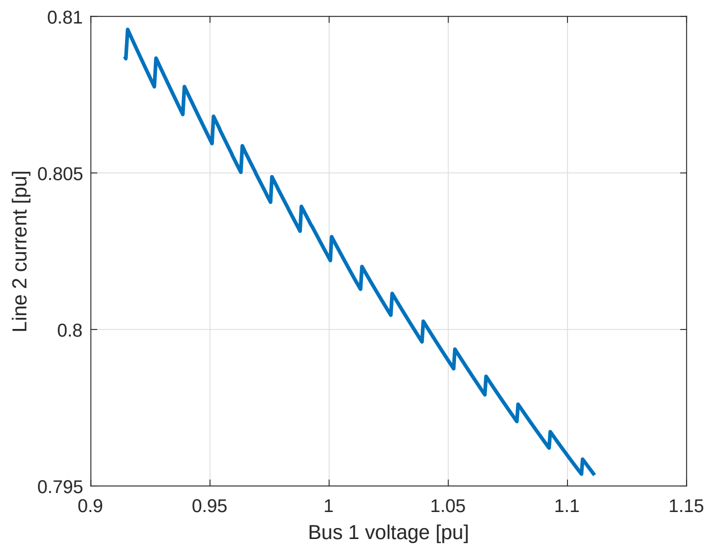

Fig. 4.9: Line 2 flow vs Bus 1 voltage characteristic

line is obtained by setting the reactive power injection at Bus 1 and solving the power flow, then measuring both the current flow on Line 2 and the voltage at Bus 1. Note that the jagged parts of the curve are caused by nearby voltage control devices such as transformer tap changers (not shown in the system schematic). The approximate sensitivity obtained from the figure is -0.075. This means that effective control of the flow on line is not possible even by varying the voltage magnitude across the entire secure voltage range.

In both figures, the sensitivity of flow on the line to either voltage or load is very small. Therefore, neither of these parameters can be used to solve the transfer capability problem. This exhausts the control parameters of a STATCOM with energy storage and therefore such a device is not sufficient to address the power transfer problem.

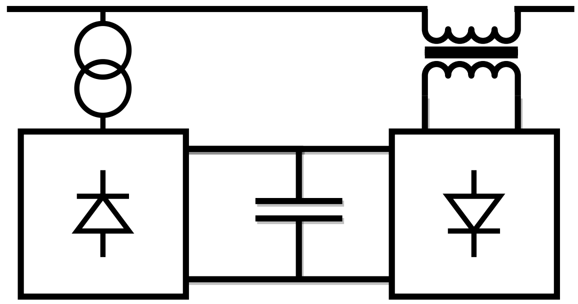

Fig. 4.10: Schematic of a basic UPFC

4.2 Unified Power Flow Controller

A Unified Power Flow Controller, or UPFC, is a power electronics based device which has two functions. The first is to provide reactive power support to the grid in the same manner as a STATCOM. In fact a UPFC contains a Statcom within it as one of its components. The additional part of a UPFC that makes it different than a STATCOM is a second VSC which is connected to a transformer which has one winding in series with a transmission line. Since a UPFC is essentially two STATCOMs, it has approximately double the footprint and operating cost requirements [14]. A simple schematic of a UPFC is shown in Figure 4.10.

The additional series connection allows the UPFC to inject a series voltage onto the transmission line. From the system perspective, this looks like a variable impedance in series with the transmission line. By controlling the series voltage injected on the line, the UPFC can make the transmission line appear to have a different impedance. This is useful when there are several parallel lines and it is desired to control how power flow is shared among the parallel lines. For example, the impedance of the line with the UPFC can be made to look larger than the other parallel lines which would push power off of the controlled line and onto the other lines. Similarly, the apparent impedance of the line could be made to look smaller which would cause more power to flow along the line.

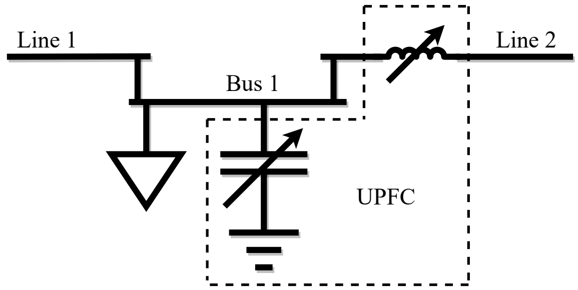

Fig. 4.11: Schematic of the UPFC at Bus 1 as modeled

4.2.1 UPFC Steady State Analysis

Using the characteristics of a UPFC, a model suitable for a power flow solution can be constructed using just 2 elements: a continuously variable impedance in series with a transmission line, and a continuously variable shunt reactive device at a nearby bus. Figure 4.11 shows a schematic of a UPFC model inserted into the system of interest in this way. The series impedance is inserted in series with Line 2 and the shunt reactive element is located at Bus 1. Although the series impedance is shown as an inductor, this does not fully represent the series part of a UPFC because an inductor does not absorb or supply active power. In general it should be modeled as a variable voltage source. Similarly, the shunt device is shown as a capacitor however again this does not fully represent a UPFC. In general this should be modeled as a variable current source. In both cases the active power characteristics of a UPFC can't be represented with purely reactive devices. A purely reactive UPFC model was used because a source-based model can't be easily modeled in PSSE and in this case a purely reactive model is sufficient to demonstrate that a UPFC has the required control characteristics. This model was inserted into the detailed power flow model used in previous sections. The parameters of the model were varied in order to obtain the steady state control characteristic of the model.

This model was used in a system configuration set up such that Line 2 was overloaded in order to demonstrate the ability to satisfactorily control the flow on the line and the voltage at Bus 1. The

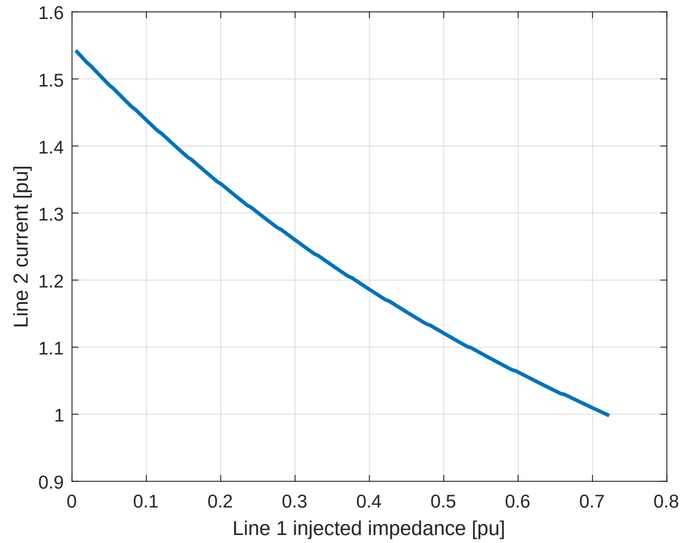

Fig. 4.12: UPFC series impedance vs Line 2 current

impedance was varied in small steps and the model was solved while monitoring the current flow on Line 2. At the same time, the shunt device was used to control Bus 1 to 1.0 pu voltage. Each of these solved power flows represents one point of data. Figure 4.12 shows a plot of the impedance of the series element against the current on the line. This curve represents the steady state control characteristic of current with respect to impedance for this system configuration. Figure 4.13 shows a plot of the impedance of the series element against the reactive power injection required at Bus 1 in order to maintain the bus voltage at 1.0 pu. This curve can be thought of as a corollary control characteristic for this system condition. The jagged parts of the curve are caused by nearby voltage control devices reacting to the change in current on Line 2 and any associated voltage deviations at their control buses. The voltage at Bus 1 is not shown in a figure since it is trivially held at 1.0 pu voltage identically to the curve shown in Figure 4.6.

The voltage stability problem is trivially solved since a UPFC has the same capability as a STATCOM, and it was demonstrated in section 4.1.2 that a STATCOM is sufficient to resolve the issue. Figure 4.12 demonstrates that it is feasible to solve the transfer capability problem using a

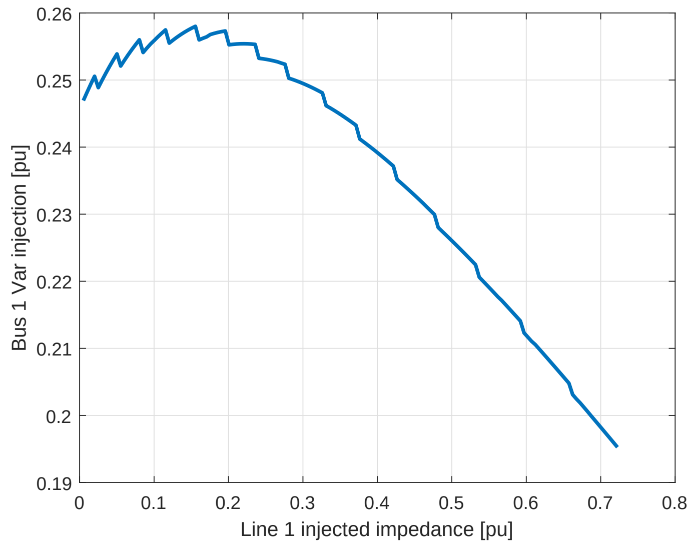

Fig. 4.13: Bus 1 UPFC series impedance vs Var injection

suitably sized UPFC. It is possible in a series of small steady state steps to reduce the current on the line from an initial heavily overloaded condition back down to within its rating of 1.0 pu. Figure 4.13 shows that the VAr requirement at Bus 1 is not unreasonable in the process of reducing the flow on the line. Therefore a UPFC in steady state is sufficient to solve both the voltage problem and the transfer capability problem.

4.3 Summary

In this chapter, solutions to the transmission system constraints were presented and explored. A switched capacitor bank was analyzed and shown to provide some level of voltage support however it is not sufficient to address the voltage stability problem. An SVC/STATCOM was analyzed and shown to provide sufficient voltage support to address the voltage stability constraint however neither would be able to address the thermal constraint. Finally a UPFC was presented and analyzed, and shown to sufficiently resolve both of the constraints. A UPFC is selected as the most suitable solution and is the subject of study in subsequent chapters.

Chapter 5

Dynamic Modeling

5.1 Control System

5.1.1 UPFC Shunt Controls

All analysis until this point has been performed in a power flow program which requires only minimally active controls (e.g. a voltage set point). A detailed analysis of the control action is required before a dynamic model can be constructed. Let's begin with a simple power transfer across a reactor as shown in Figure 5.1. In this example the UPFC terminal would be on the left side and the power grid would be on the right side. This is a useful analysis since the power flow across a reactor provides insight into the characteristics of many devices, such as an ideal transformer or a lossless transmission line. Note that a transmission line (lossless or otherwise) has capacitance which may be significant however it is not necessary to model the capacitance for this analysis. The shunt part of a UPFC is connected to the grid through a transformer therefore this model is applicable. Consider the receiving end voltage with magnitude V_r as the reference voltage with angle 0 and the sending end current with magnitude I_s and phase angle θ with respect to the

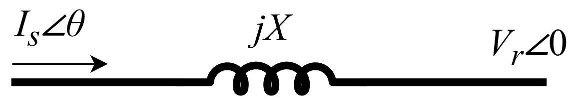

Fig. 5.1: A reactor with current flowing through it

receiving voltage. Convert the phasor from polar notation to rectangular notation with j as the complex unit as follows

$$V_r\angle 0 = V_r cos\left(0\right) + jV_r sin\left(0\right) = V_r \tag{5.1}$$

$$I_s\angle\theta = I_s cos\left(\theta\right) + jI_s sin\left(\theta\right) \tag{5.2}$$

Therefore the power which enters the grid at the receiving end is

$$P + jQ = V_r\left(I_s cos\left(\theta\right) + jI_s sin\left(\theta\right)\right)^* \tag{5.3}$$

From which is derived

$$P = V_r I_s cos\left(\theta\right) \tag{5.4}$$

$$Q = -V_r I_s sin\left(\theta\right) \tag{5.5}$$

Note that the power leaving the terminals of the UPFC must also include the power consumed by the reactor and therefore is

$$P_t + jQ_t = V_r\left(I_s cos\left(\theta\right) + jI_s sin\left(\theta\right)\right)^* + jI_s^2 X \tag{5.6}$$

However the extra power consumed by the reactor does not influence the behavior of the receiving end and is therefore neglected. If the sending end current angle is set $\theta = 0°$, then equations 5.4 and 5.5 simplify to

$$P = V_r I_s \tag{5.7}$$

$$Q = 0 \tag{5.8}$$

Observe that the reactive power transfer is zero. This means that if the sending end current is in phase with the receiving end voltage then the active power transfer can be controlled independently without any reactive power transfer. All that is needed to accomplish this is for the sending end current to be in phase with the receiving end voltage and the magnitude can be varied to control the power. Now set $\theta = 90°$, then equations 5.4 and 5.5 simplify to

$$P = 0 \tag{5.9}$$

$$Q = -V_r I_s \tag{5.10}$$

Note that in this case, the active power transfer is zero and the reactive power transfer is not. All that is necessary to accomplish this is for the sending end current to be in quadrature with the receiving end and then the magnitude can be varied to control the power.

With these two observations in mind, a sending end current will be constructed with two components, one in phase and one in quadrature to the receiving end. The in-phase component is designated I_d and the quadrature component is designated I_q. These two components can independently control both the active and reactive powers at the same time. A control system

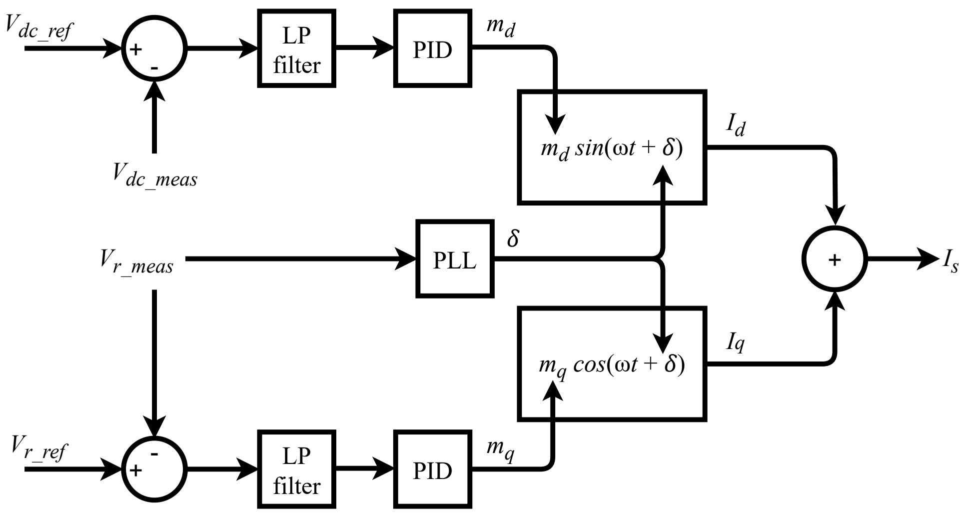

Fig. 5.2: UPFC shunt control system

for the shunt part of a UPFC can be derived from this since the device is capable of producing arbitrary voltage waveforms. The shunt device will be used for two purposes: to control the AC bus voltage, and to control the DC bus voltage. The reactive power transfer from the shunt device directly influences the bus voltage, and the active power transfer directly influences the DC bus voltage. Therefore it is convenient to select these two quantities as the control variables rather than directly controlling power transfer.

Note that the assumption that the receiving end voltage is constant may not be true. If the receiving end voltage varies with power transfer then the active and reactive controls will be coupled. Uncoupling the controls requires knowing how the receiving voltage varies with power transfer which in turn requires knowing the network impedance behind the voltage. This is difficult knowledge to obtain since measuring the network impedance in general is not easy and it may vary with changing network conditions. Therefore the control system will assume constant receiving voltage in favour of simplicity at the cost of some potential coupling between active and reactive components.

Figure 5.2 shows the control system derived from the analysis. The signals in the figure are as follows: V_{dc_ref} is the DC voltage reference, V_{dc_meas} is the measured DC voltage, V_{r_ref} is the grid bus voltage reference, V_{r_meas} is the measured grid bus voltage, I_s is the sending end current signal. Both measured signals will go through low pass filters to remove high frequency noise before entering the PID controllers. Two PID controllers are used to control the magnitudes of the components based on error signals from the measured quantities. The $m_d sin(\omega t + \delta)$ block will produce a sinusoid that is in phase with the measured AC bus voltage and therefore controls active power as shown in equations 5.7 and 5.8. The $m_q cos(\omega t + \delta)$ block will produce a sinusoid that is in quadrature with the measured AC bus voltage and therefore controls reactive power as shown in equations 5.9 and 5.10. A Phase Locked Loop (PLL) is used to track the phase angle of the receiving end voltage which then feeds into the two sinusoidal components. The sending end current signal is constructed by summation. This signal will be passed to the UPFC shunt device which will translate it from a signal into a physical current. The mechanism by which this is done will be discussed in future sections.

5.1.2 UPFC Series Controls

A schematic of the series part of a UPFC is shown in Figure 5.3. The UPFC is connected to the sending end of a transmission line through a transformer connected in series with the transmission line. The transmission line is represented by the inductor on the right. The output current of the UPFC will be directly proportional to the line current according to the transformer winding ratio. Therefore if the control system directly controls the output current of the UPFC, then the power flow down the line can be directly controlled. From this perspective the series control system and equivalent circuit becomes identical to that considered in the shunt case. All of the same analysis holds true and the control system is directly obtained.

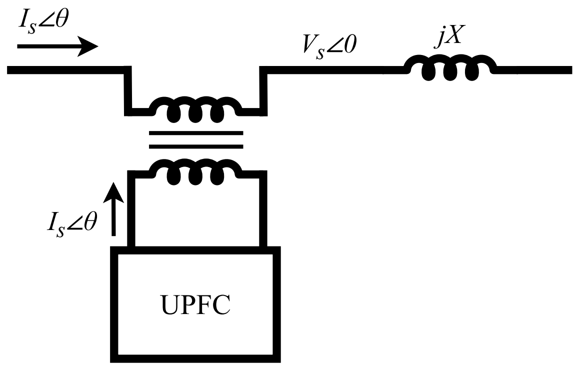

Fig. 5.3: Series components of a UPFC with current flow

Figure 5.4 shows a schematic of the series element control system where P_{meas} is the measured active power flow down the line, Q_{meas} is the measure reactive power flow down the line, and V_s is the sending end voltage (from the perspective of the transmission line). Error signals are filtered before entering separated PID controllers. The PID controllers generate the component magnitudes which are then constructed into a sinusoidal signal which is passed on to the valve group. The control system architecture is identical to the shunt control system.

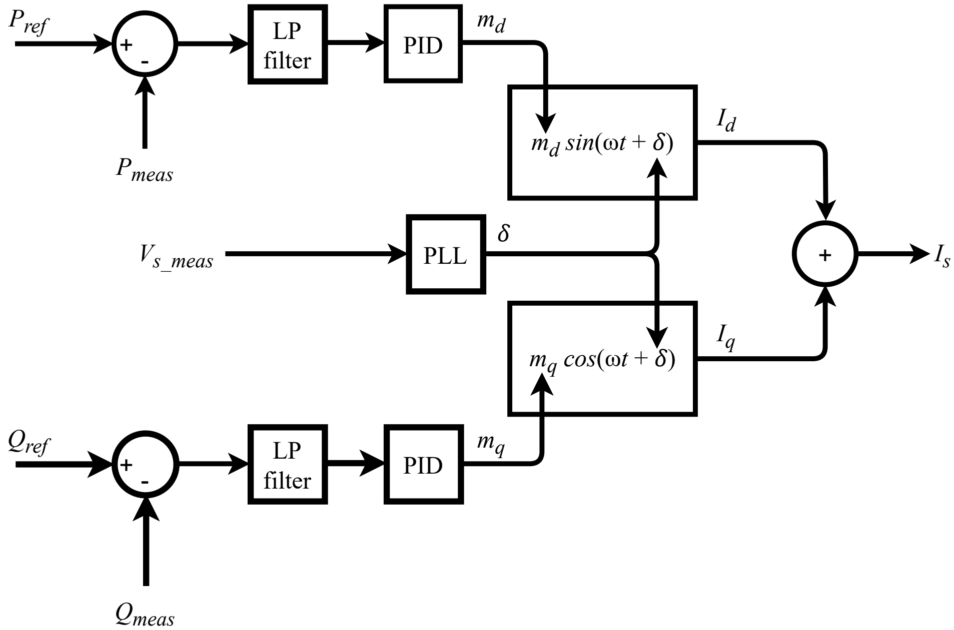

Fig. 5.4: UPFC series control system

5.1.3 Hysteresis Current Control

Both shunt and series control systems directly generate the desired converter current output signal, therefore a switching scheme which directly generates a physical current is required. Hysteresis current control is the switching method selected.

For a PWM based voltage source converter, the control system directly generates the desired voltage waveform signal and the switching is performed to convert it to a physical voltage. If the switching frequency is very high compared to the signal, then the signal is converted approximately one-to-one to the physical voltage (high order harmonics aside). In this paradigm, the switching frequency can be specified as desired. Physical current appears as a secondary dynamic as a result of whatever voltage waveform is generated. However it is possible instead to measure and directly control the current.

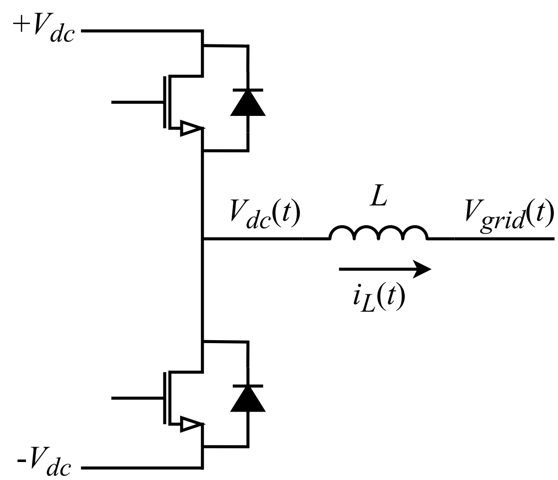

Fig. 5.5: Single phase valve

Let's consider Figure 5.5 which shows a single phase of a two-level valve group. The phase current of this VSC obeys equation 5.11 where $i_L(t)$ is the phase current, $V_{dc}(t)$ is the converter output voltage waveform, $V_{grid}(t)$ is the AC grid voltage, and L is the phase reactor inductance.

$$\frac{d}{dt}i_L(t) = \frac{V_{dc}(t) - V_{grid}(t)}{L} \tag{5.11}$$

If the rate of change of current is very fast compared to $V_{grid}(t)$ then $V_{grid}(t)$ can be assumed constant. This means that the current will simply increase or decrease linearly depending on which level the VSC is outputting. The phase current will oscillate between linearly increasing and linearly decreasing as the VSC switches between its two states. If the desired current signal also varies slowly compared to the rate of change of current as determined by equation 5.11 then there is the basis for a control system to directly generate a current waveform.

Let's define $I_{sig}(t)$ to be the desired output current, and h to be the maximum deviation from the desired current. Current directionality is with respect to exiting the converter. The control method will be as follows. When the VSC is outputting its high voltage level then the current will be increasing. When the current reaches $I_{sig}(t) + h$ then the VSC should switch to the low voltage

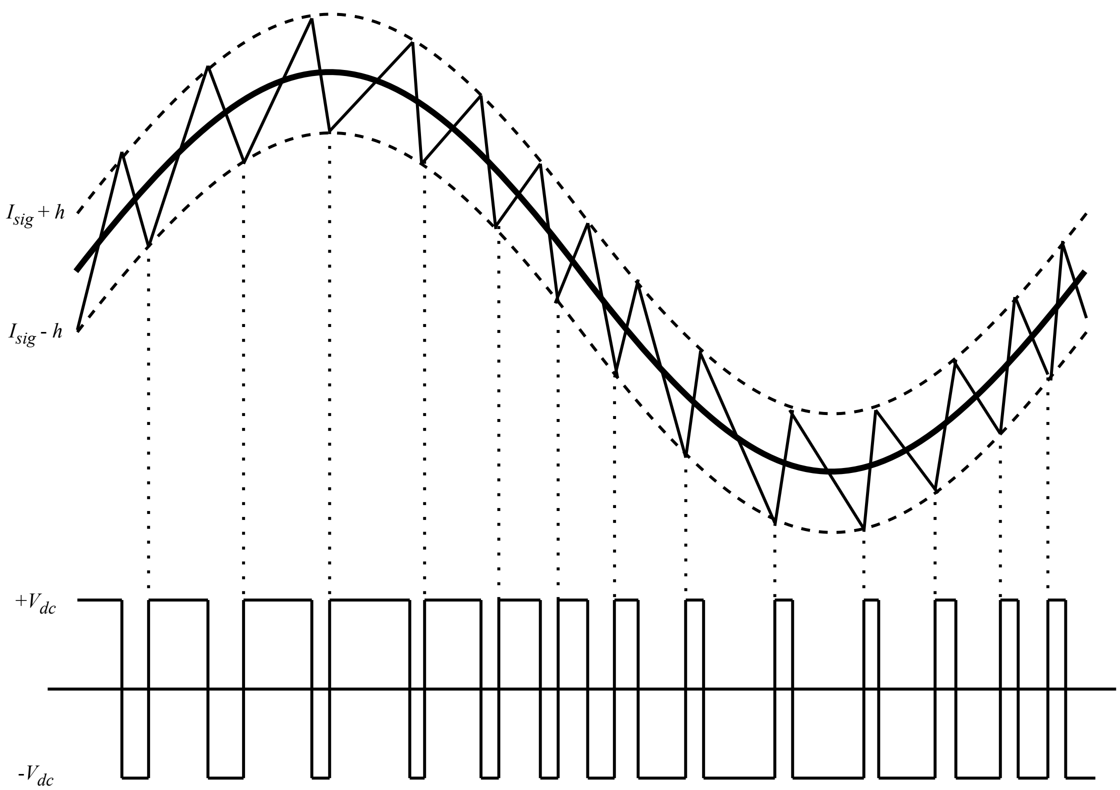

Fig. 5.6: Hysteresis Current Control

level. The current will decrease. When the current reaches $I_{sig}(t) - h$ then the VSC should switch back to the high level. Figure 5.6 illustrates this control scheme. The vertical dotted lines in the figure show the positive edge of the voltage waveform.

This is called hysteresis current control because the current waveform level oscillates within a bound of the desired current signal. The current signal is directly generated and the voltage can be thought of as a secondary dynamic of the current waveform. The disadvantage of this control scheme is apparent in the figure. The spacing between vertical lines is the switching period and it is not constant over one cycle; the switching period varies with the magnitude of the output current. This makes AC filtering difficult compared to a voltage output control scheme. In a voltage output scheme the switching frequency can be set constant and therefore AC filtering can be tuned to match. With a varying switching frequency, the AC harmonics to filter out will also vary and therefore passive tuned filters can't be used.

Some basic characteristics of the frequency variation can be analyzed [15]. Assume switching is fast enough that $V_{grid}(t)$ and $I_{sig}(t)$ are both approximately constant. The time t_{up} of the current increasing state is

$$t_{up} = \frac{2hL}{+V_{dc} - V_{grid}(t)} \tag{5.12}$$

similarly, the time t_{down} spent in the current decreasing state will be

$$t_{down} = \frac{-2hL}{-V_{dc} - V_{grid}(t)} \tag{5.13}$$

the total switching period T is

$$T = t_{up} + t_{down} = \frac{2hL}{+V_{dc} - V_{grid}(t)} - \frac{2hL}{-V_{dc} - V_{grid}(t)} \tag{5.14}$$

therefore switching frequency f is

$$f = \frac{1}{T} = \frac{V_{dc}^2 - V_{grid}^2(t)}{4V_{dc}hL} \tag{5.15}$$

The maximum switching frequency will occur when $V_{grid}(t) = 0$ which gives

$$f_{max} = \frac{V_{dc}}{4hL} \tag{5.16}$$

5.2 Model Schematic

Unlike in the steady state analysis, there was no model available to use for the dynamic analysis. Therefore a model was developed in PSCAD and is shown in Figure 5.7. The solid lines represent electrical components and the dotted lines and boxes represent control signals or measurements. The voltage source on the left side of the figure is the Thevenin equivalent source for System A and the voltage source on the right side of the figure is the Thevenin equivalent source for System B. The angle of the System B source is arbitrary but was selected so that the initial flow on Line 2 was within its operating limits. The load on Bus 1 was set to a typical daily peak load.

The control system for the shunt part of the UPFC takes its measurements from the locations shown in the figure. The voltage magnitude and angle from Bus 1, and the voltage magnitude of the DC bus capacitor feed into the controller. The control system constructs the desired current waveform and sends the control signals to the valve group.

The control system for the series part of the UPFC takes its measurements as shown in the figure. The voltage angle from the sending end of Line 2, and the active and reactive power at the sending end feed into the control system. The control system constructs the desired waveform and feeds the control signals into the valve group.

Line 1 and Line 2 are modeled using the frequency dependent, conductor geometry based models which are available in PSCAD. The geometrical parameters were obtained from the system

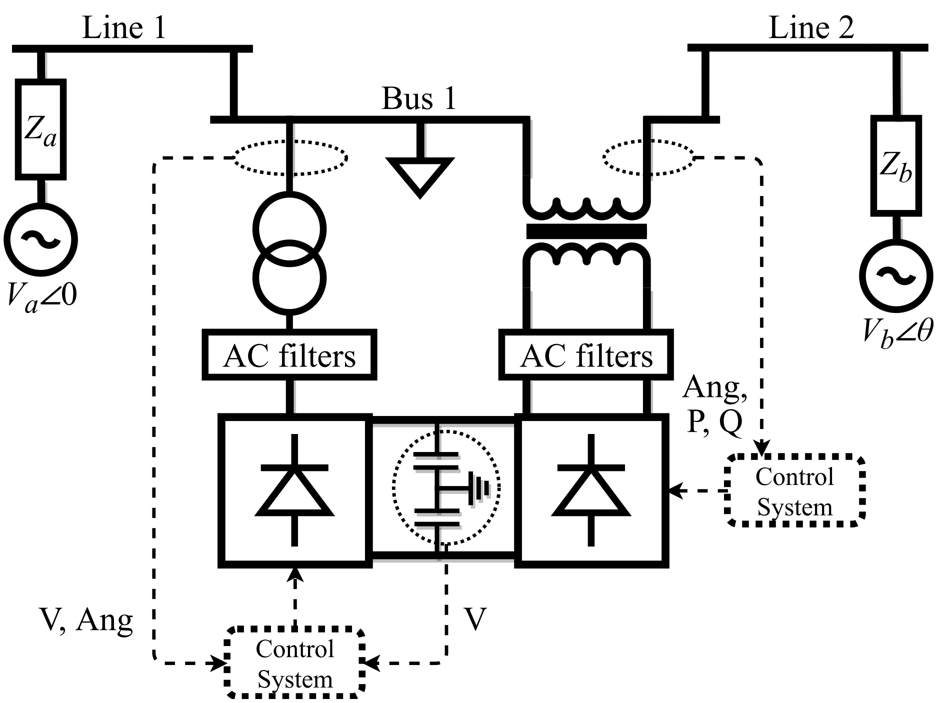

Fig. 5.7: Full UPFC Model

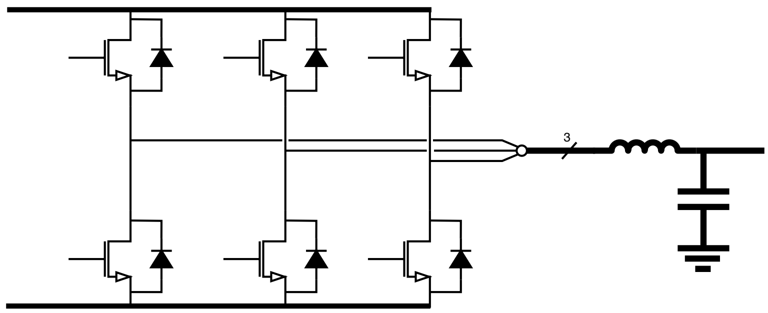

Fig. 5.8: Valve Group

owners and used in the model. Each of the shunt and series valve groups are made up of a two-level VSC, each of which have AC filtering to remove some of the harmonics from the injected voltages. The valve groups share a DC bus capacitor. Figure 5.8 shows a schematic of the valve group and its AC filter. The AC filter is a simple second order low pass filter.

5.3 Model Parameters

The following sections detail the model parameters of the various components and control blocks.

- **Station Load**

The load on Bus 1 is a constant current load set to 0.482 pu active power and 0.104 pu reactive power at 1.0 pu voltage.

- **Transformers**

The transformer parameters are shown in Table 5.1. The same transformer is used for both shunt and series components.

Table 5.1: Transformer parameters

MVA rating	0.65 pu
Winding ratio	10
Winding 1 Type	wye
Winding 2 Type	wye
Leakage reactance	0.06 pu
Copper losses	0.003 pu
Saturation	None

Table 5.2: AC filter parameters

L	6.78 mH
C	115 μF
fo	300 Hz

- **AC Filtering**

The AC filtering for both the series and shunt elements are simple low pass LC filters. The capacitor was selected to provide 0.1 pu MVAr at nominal voltage. The inductor was selected to get the desired cutoff frequency of $300Hz$. The parameters are shown in Table 5.2.

- **DC Capacitor**

The DC capacitor will provide the DC voltage which will be switched to produce an AC waveform for interfacing with the grid. Nominal DC voltage will set at 123% of the nominal peak AC voltage. This will provide ample room for variation in the AC output waveform.

The size of the capacitor will affect the size of the voltage ripple as well as converter dynamic performance. The following equation relates the capacitor size C to its associate time constant τ [16]

$$\tau = \frac{energy\, stored}{nominal\, power\, rating} = \frac{CV_{dc}^2}{2P_n} \tag{5.17}$$

For this converter, the time constant has been selected as $2ms$ which produces capacitor size of $375\mu F$

- **Current Hysteresis**

The maximum switching frequency is selected to be $2000Hz$. Equation 5.16 then provides the maximum current error h to be $0.2pu$.

- **Control Signal Filtering**

All error signals pass through a 4th order Butterworth low pass filter with cut off frequency of $500Hz$.

5.3.1 PID Controllers

The integral components of every control system are internally limited to nominal peak current in order to prevent windup. Additionally the sum of each PID group is hard limited to nominal peak current to prevent the UPFC from attempting to produce current over nominal.

The shunt PID controllers have two sets of parameters. One set for strong-network conditions (i.e. system intact) and a second set for weak-network conditions (i.e. post Line 1 contingency). The controller parameters depend strongly on the coupling between the network and the UPFC. When the network conditions change, the previous control parameters may no longer be suitable for the new network condition. There are line protection relays at the station which detect fault conditions and locations. These relays send signals to open the correct breakers to clear the fault. The UPFC can co-opt the breaker open signal as a trigger for the controller to switch to the second set of parameters. This signal will tell the controller to change its block gains and also to reset the states in each integral block. Resetting the integral states is necessary because the faulted network condition is likely to pin the internal integral state to one of its bounds which is a poor

Table 5.3: Controller gains

PID component	Strong network	Weak network
shunt Id kp	1.72E-1	8.25E-2
shunt Id ki	2.51E+0	7.25E-1
shunt Id kd	0.00E+0	2.84E-5
shunt Iq kp	5.44E+1	7.44e+0
shunt Iq ki	3.60E+3	6.89E+1
shunt Iq kd	0.00E+0	9.41E-2
series Id kp	2.80E-4	N/A
series Id ki	1.26E+0	N/A
series Id kd	0.00E+0	N/A
series Iq kp	1.1E-3	N/A
series Iq ki	8.02E-1	N/A
series Iq kd	0.00E+0	N/A

initial condition for the UPFC to transition to post-fault operation. A typical time delay from fault inception to fault clearing is five cycles (0.083 s).

Note that the loss of Line 1 will cause the station be radially fed from Line 2 which means that the series element of the UPFC can no longer operate. Therefore the same trigger (fault clearing signal to the breaker) will also cause the series element to block and bypass. In general, a different parameter set could be determined for every relevant network condition. However in this case the focus is the Line 1 contingency. The Line 2 contingency is not studied but may require a similar study to determine suitable controller parameters for post fault network conditions.

Table 5.3 shows the gains for each block in every controller. The controller gains were determined using simplex multi-variate optimization. This applies to both the strong-network and weak-network parameter sets. The optimization was performed such that the sum of the control error signal and DC voltage deviation were minimized. This approach provides a balance between a fast control response and low DC voltage disturbance. DC voltage disturbance was selected as an error signal source because DC voltage variation is detrimental to the UPFC performance. Note that gains are displayed using shortened scientific notation.

5.4 Summary

In this chapter, a UPFC is designed in detail. The electrical components are selected. The control system for the UPFC is built from a mathematical basis. The controller scheme is selected, designed, and tuned using an optimization procedure.

Chapter 6

Model Performance

This chapter will present and discuss various performance aspects of the model developed in the previous chapter.

6.1 Control system step responses

The first performance characteristic of the model which will be discussed is the step response to the control parameters. Each of the following three parameters will be stepped: AC voltage, active power, and reactive power. Note that the DC voltage control system will never receive any reference changes since it is always controlled to 1 pu. Therefore, a step response for DC reference voltage was not performed.

An acceptable step response must be obtained for each control parameter. This means that in addition to a stable response, some criteria must be met. For controller step responses: controlled parameter overshoot must not exceed 20% of the step size, AC bus voltage coupling must not exceed 0.01 pu, DC bus voltages must remain within the range 0.7 pu to 1.3 pu at all times, and power coupling on Line 2 must not exceed 0.05 pu. Responses must settle within 0.167 s. The criteria for system fault responses is different. During the fault, there is no criteria. Beginning with the first swing after the fault clears, both AC and DC voltages must remain within the range 0.7 pu to 1.3 pu, and return to within the range 0.9 pu to 1.1 pu after the transient settles.

6.1.1 Voltage Reference Step Response

Figure 6.1 shows the step response to a 0.05 pu change in the AC voltage reference. Both a positive step and a negative step are shown. The AC voltage response (top plot) shows a settling time of approximately 0.1 s which is 6 cycles. There is some coupling to the DC voltage (middle plot) which experiences an initial deviation of 0.08 pu followed by controller overshoot of approximately 0.025 pu. This is expected since the decoupling assumptions made in the design of the control system are not perfectly accurate. The active power and reactive power response (bottom plot) show almost no disturbance at all. Overall, these responses are well within the criteria.

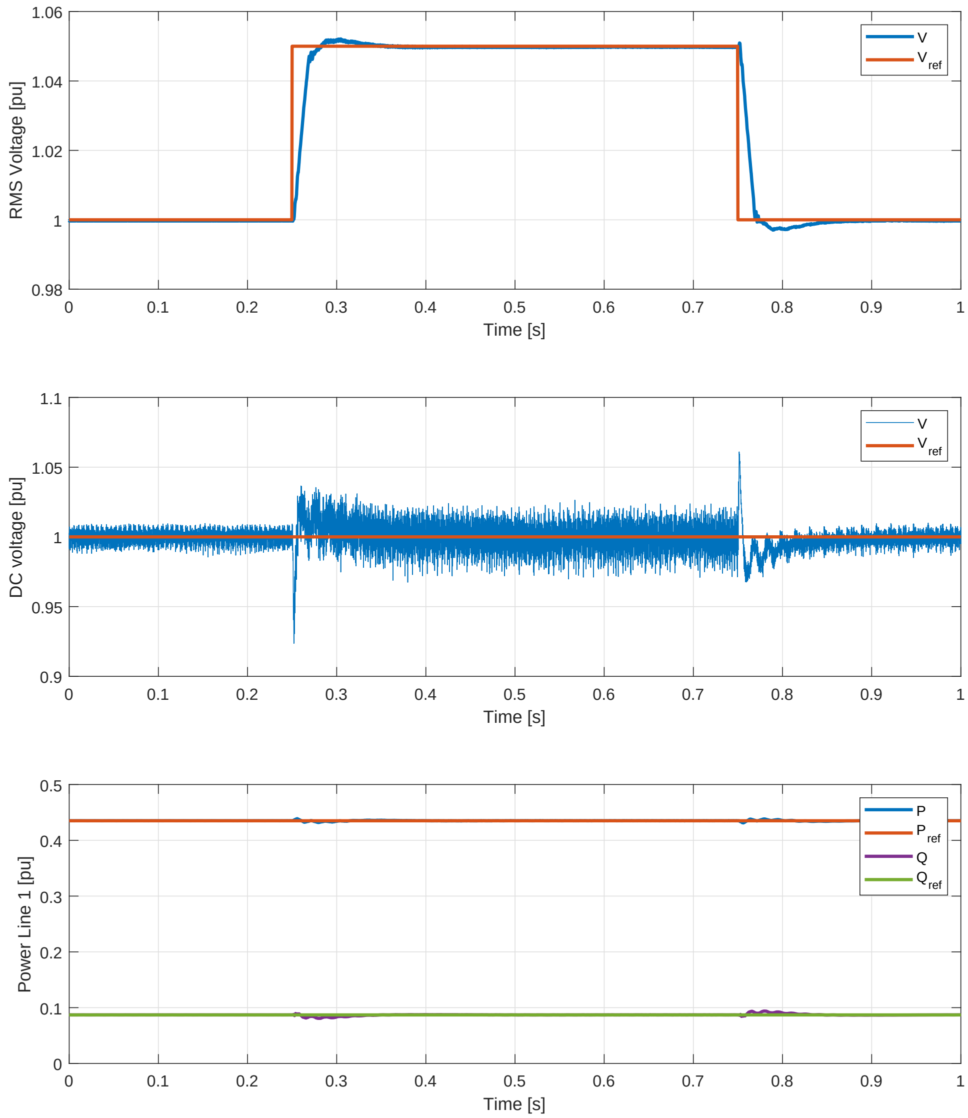

Fig. 6.1: Voltage reference step response

6.1.2 Active Power Reference Step Response

Figure 6.2 shows the step response to a 0.1 pu change in the active power reference. Both a positive step and a negative step are shown. The active power response (bottom plot) settling time is approximately 0.15 s with a small overshoot of approximately 0.01 pu. The longer response is intentional to minimize voltage disturbance caused by the change in power flow. The AC voltage response (top plot) shows some coupling with a disturbance of approximately 0.003 pu. This is well within the criteria. There is some coupling to the DC voltage (middle plot) which experiences a deviation of approximately 0.015 pu. The reactive power response (bottom plot) shows coupling of approximately 0.015 pu. There was no attempt to decouple the shunt elements (AC and DC voltage control) from the series elements (active and reactive power control) therefore the coupling is expected. The small amount of coupling between the active and reactive responses is due to the assumptions made in the design stage. Namely, the transmission line was assumed to be lossless and the source impedance behind the transmission line was not considered. However, these responses are all within the criteria.

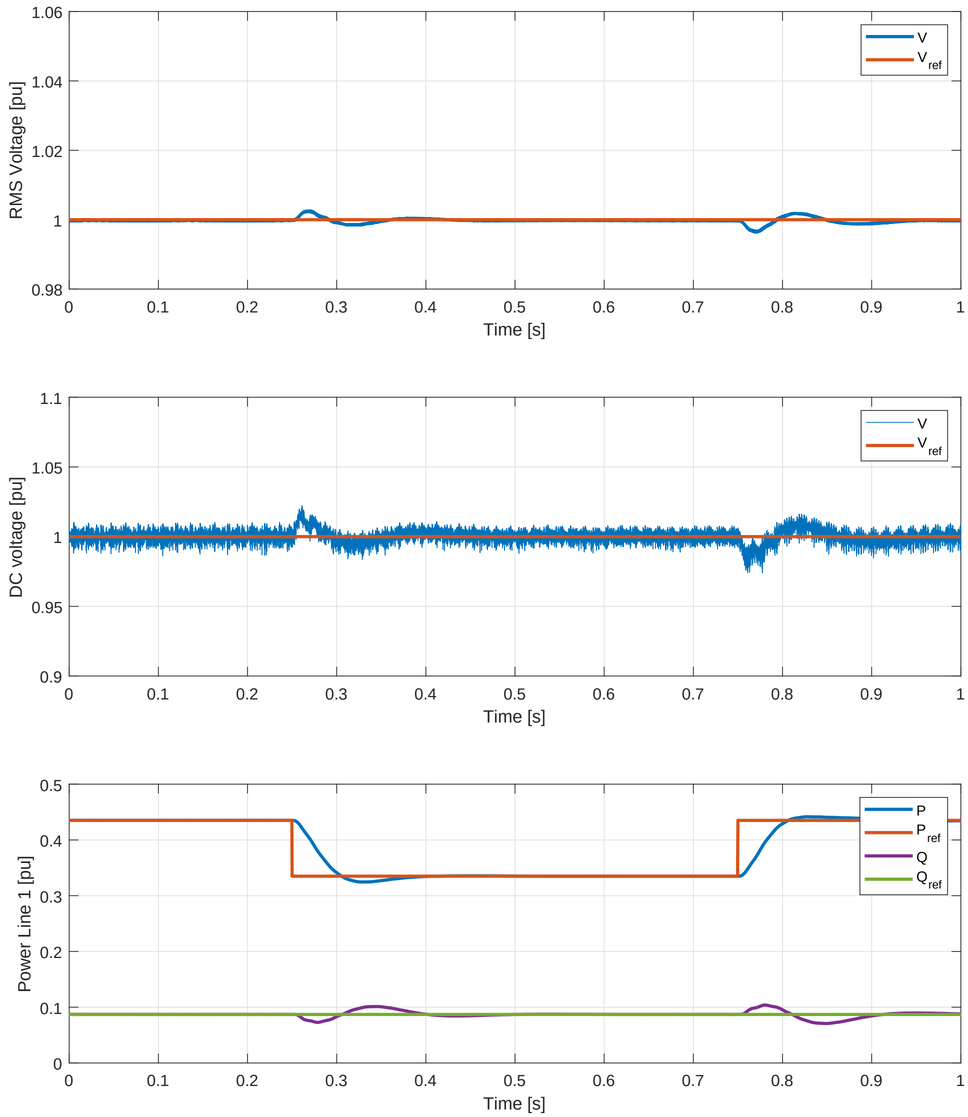

Fig. 6.2: Active power reference step response

6.1.3 Reactive Power Reference Step Response

Figure 6.3 shows the step response to a 0.1 pu change in the active power reference. Both a positive step and a negative step are shown. The reactive power response (bottom plot) settling time is approximately 0.15 s with a small overshoot of approximately 0.012 pu. Again, the longer response is intentional to minimized voltage disturbance caused by the change in power flow. The AC voltage response (top plot) shows some coupling with a disturbance of approximately 0.005 pu. This is within the criteria. There is some coupling to the DC voltage (middle plot) which experiences a deviation of approximately 0.025 pu. The active power response (bottom plot) shows coupling of approximately 0.017 pu. There was no attempt to decouple the shunt elements (AC and DC voltage control) from the series elements (active and reactive power control) therefore the coupling is expected. The small amount of coupling between the active and reactive responses is due to the assumptions made in the design stage. Namely, the transmission line was assumed to be lossless and the source impedance behind the transmission line was not considered.

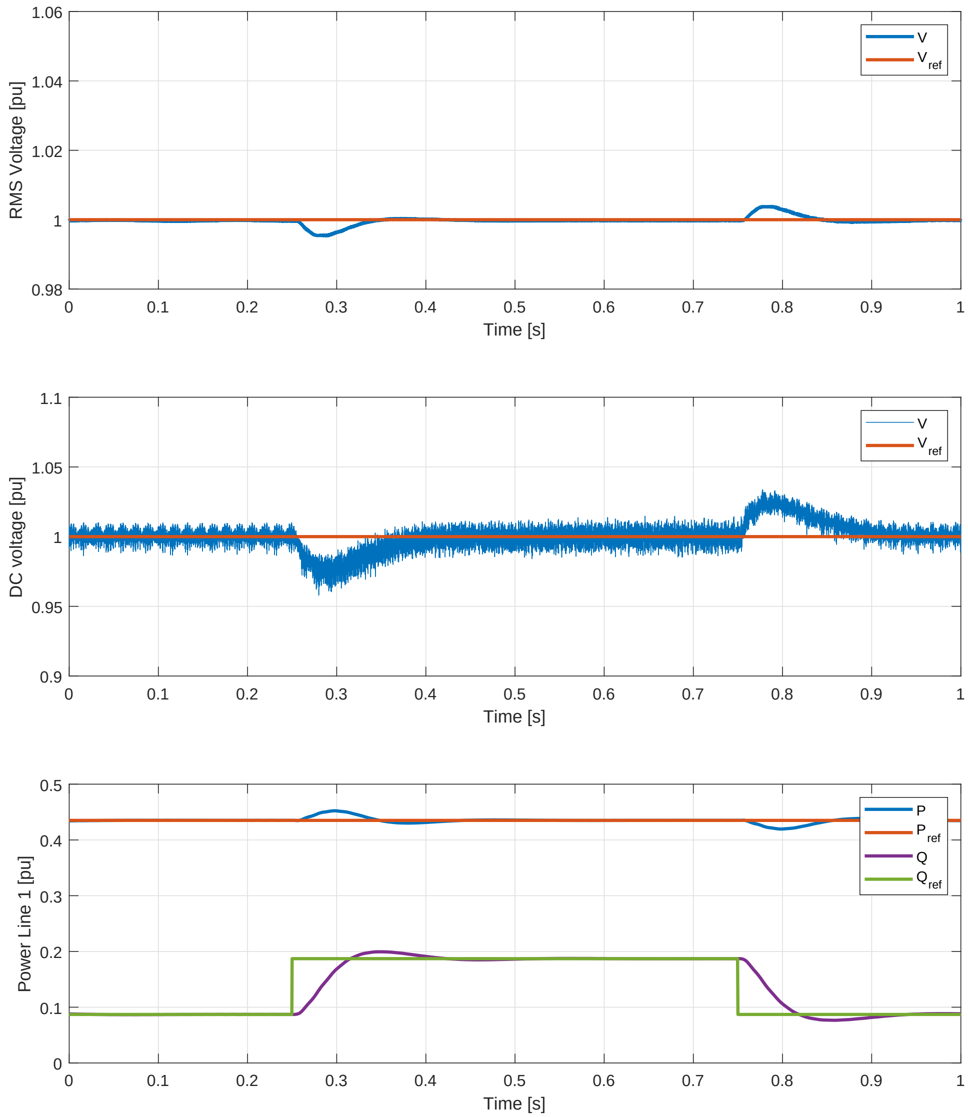

Fig. 6.3: Reactive power reference step response

6.2 UPFC Fault Response

Figure 6.4 shows the baseline system response to a three-phase, close-in, bolted fault on Line 1 without the UPFC in service. The fault duration is five cycles. The bus voltage post fault is 0.82 pu. Therefore Line 2 cannot support the load at the station when the Line 1 breaker opens. The bottom plot shows the power flow on Line 2. The power references are included on the plot despite the UPFC being out of service.

Figure 6.5 shows the UPFC and system responses to the same fault. During the fault, the AC bus voltage drops but recovers shortly after clearing with an overshoot of 0.05 pu. The DC bus voltage drops during the fault but recovers with an overshoot of 0.07 pu. The bottom plot shows the power flow on Line 2 which are controlled by the series element before the fault. The blocking of the series element post-fault operates correctly, allowing the power to flow freely. The fault response of the system meets the criteria.

6.3 Summary

In this chapter, all of the step responses are shown to be stable, and meet all criteria. The system is shown to meet the fault response criteria.

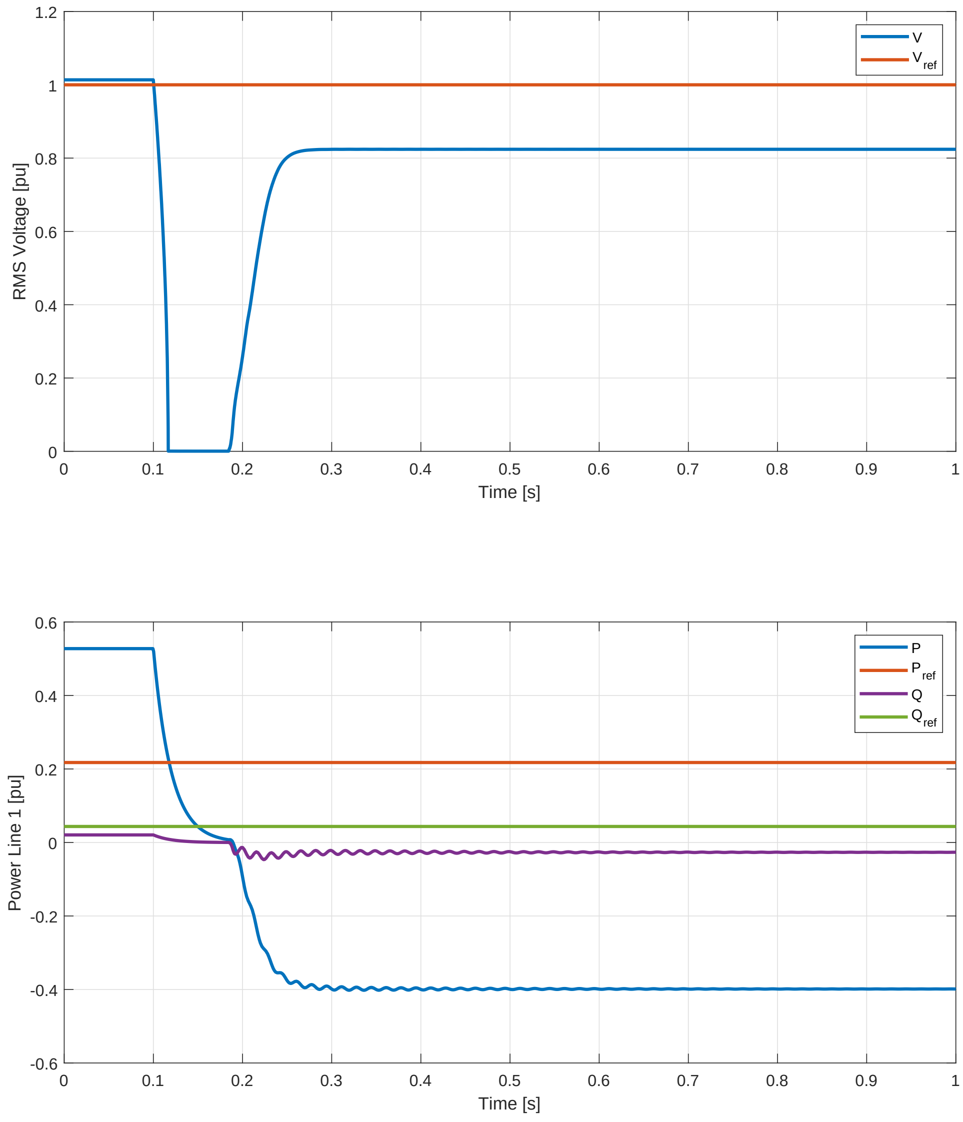

Fig. 6.4: Line 1 contingency without UPFC

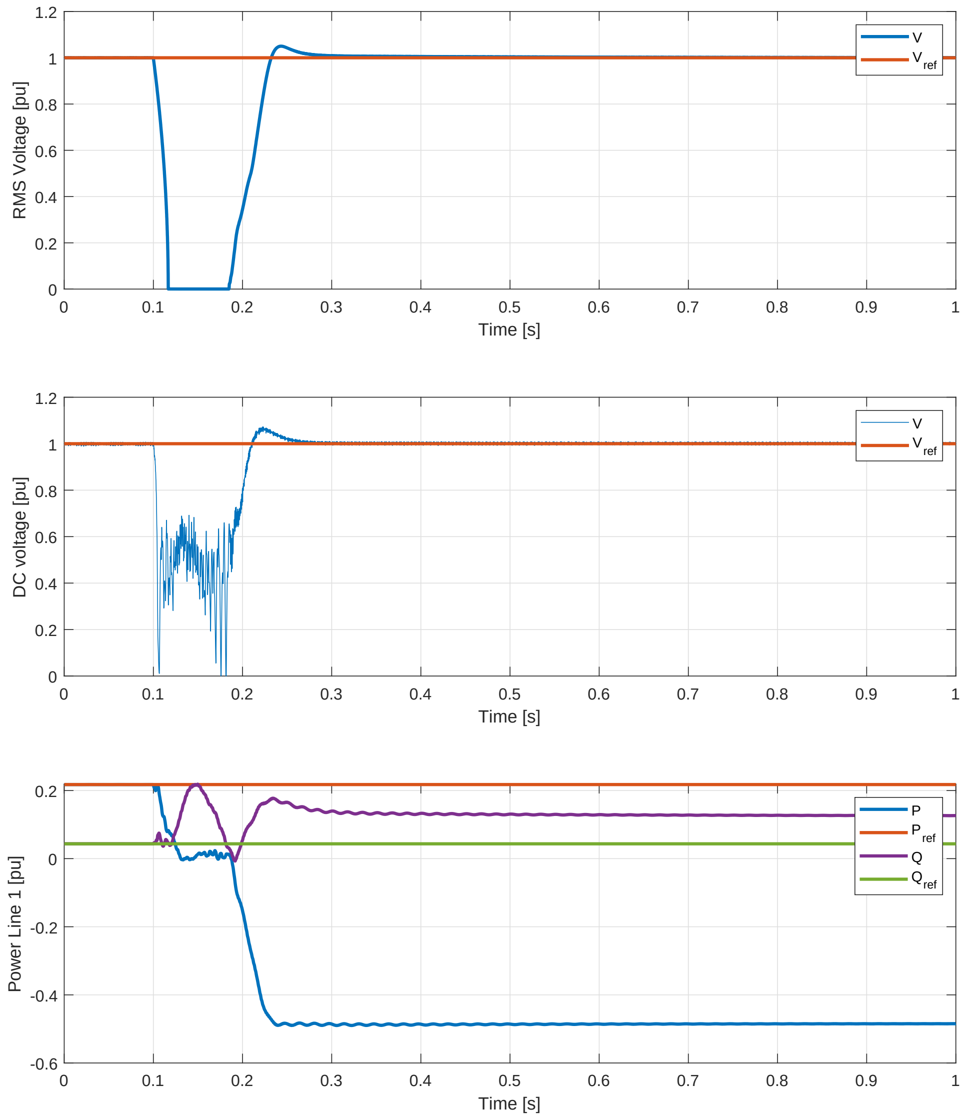

Fig. 6.5: Line 1 contingency with UPFC

Chapter 7

Grid Storage

This chapter will explore the implications of combining grid storage with the UPFC from the previous chapters.

7.1 Adding a Battery

There are two main components to a grid storage battery: the battery, and a DC-AC interface. Additionally a buck-boost interface may be required for high voltage applications. The purpose of the battery is self evident: to store and release the energy. Since batteries can only provide DC voltage, the DC-AC interface must be able to translate the DC into AC for discharge operation and also AC into DC for charging operation. In a low voltage application the battery voltage may be high enough for the DC-AC interface to directly interface the battery with the AC system. However, in a high voltage application, such as a grid storage battery, the battery voltage is not likely to be large enough for direct interfacing. In cases such as these a buck-boost interface is required. This interface can either be on the AC side in the form of a transformer or on the DC side in the form of a DC-DC converter.

The UPFC that was presented in the previous chapter already contains a DC bus and a DC-AC interface, therefore adding a battery to the system only requires interfacing the battery to UPFC's already existing DC bus. A buck-boost DC-DC converter fulfills the requirements. Figure 7.1 shows the UPFC system schematic with battery included. The battery controller uses the DC link measurement and the battery voltage measurement as control inputs. It outputs switching signals to the power electronics in the buck-boost converter, and a charge request signal to the shunt controller.

Adding a battery to the system increases the cost of the system however it provides benefits to the utility in the form of energy storage which may be used for things such as frequency control or peak shaving. Further, active power injection may reduce the need to build additional generation or transmission. The battery can store excess generation during periods of low loading and then release it during periods of high loading. This allows for increased utilization of existing generation while avoiding potential transmission constraints.

These benefits may be worth the additional costs on their own however the extra costs could be offset by controller design. The series component of the UPFC must absorb or reject active power in order to accomplish control of the flow on the transmission line. Typically the shunt system will compensate for active power which is absorbed or released by the series system. However if the battery instead provides the compensation then the shunt electrical components (such as AC transformer) can be sized down to save on costs since they are no longer required to handle as much power. The shunt controller instead acts as a low power battery charger without any series active power delta compensation.

7.2 Battery Interface Topology

A simple 2-switch buck-boost converter will be used as the DC-DC interface for the battery. The topology is shown in Figure 7.2. This converter has two switching states: S1 closed with S2 open

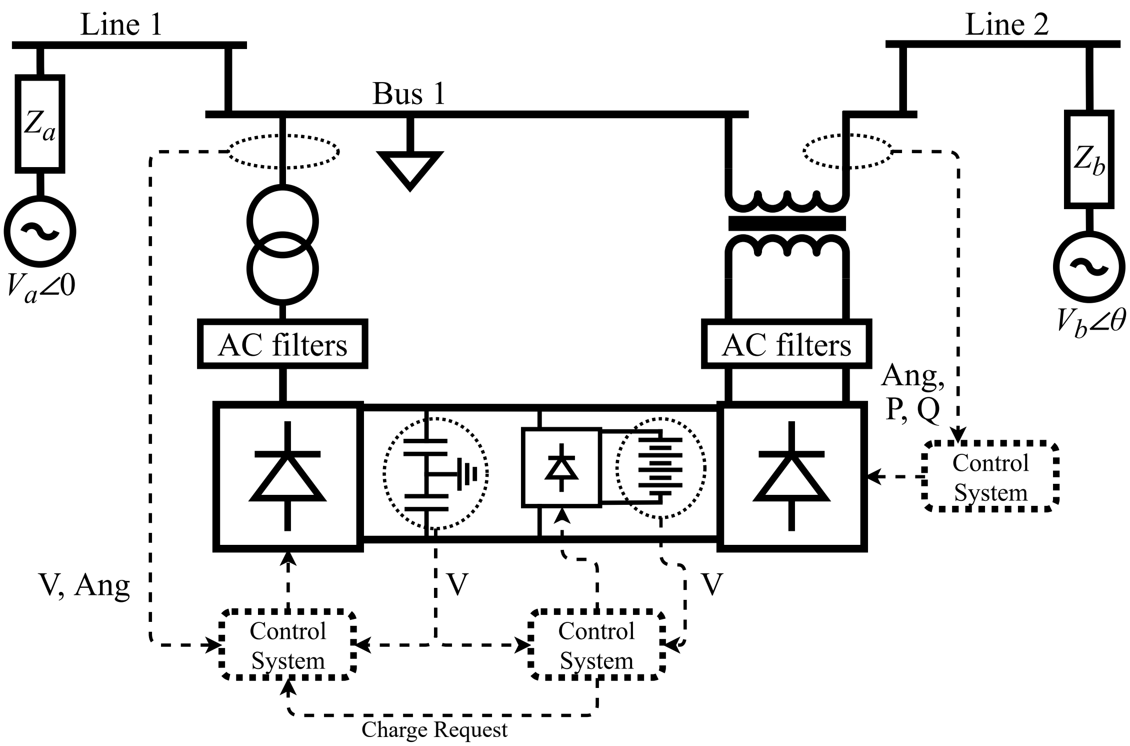

Fig. 7.1: UPFC with battery

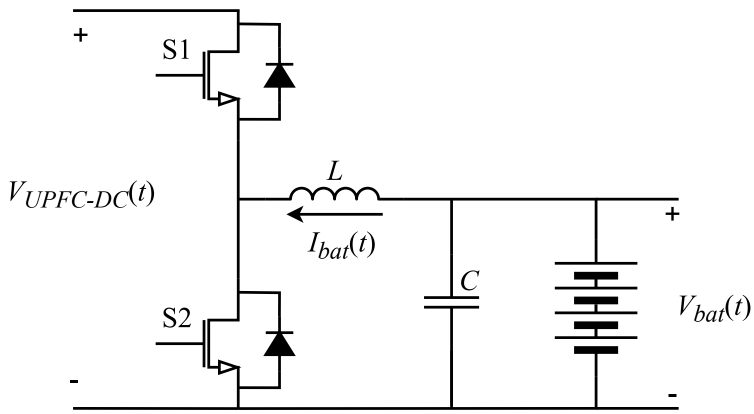

Fig. 7.2: Battery interface topology

which causes battery current $I_{bat}(t)$ to decrease, and S1 open with S2 closed which causes battery current to increase. The inductor L is required to smooth the battery current and the capacitor C smooths the battery voltage.

7.3 Model Parameters

The converter uses an inductor size of 100 mH and capacitor size of 1 μF. The battery model is a Shepherd model. A graphical depiction of the model is shown in Figure 7.3. The variables in the figure are as follows. $E(t)$ is the no load voltage, E_0 is the battery constant voltage, K is the polarization voltage, Q is the battery capacity, $I(t)$ is the battery charge, A is the exponential voltage amplitude, and B is the exponential zone time constant inverse [17]. Table 7.1 shows the parameter values used in the model. Note that the parameters as shown in the table do not correspond one-to-one with the variables in the equations shown in Figure 7.3 and they must be transformed before use in the equations. The parameters are expressed in this way because this is how they are entered in the PSCAD model.

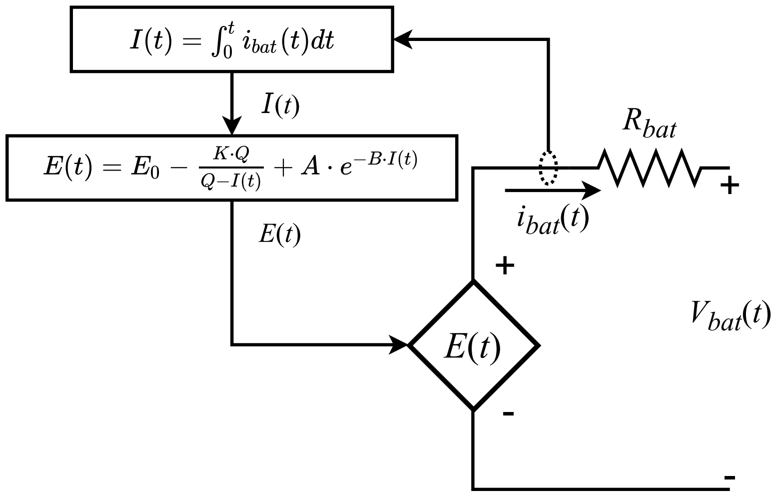

Fig. 7.3: Shepherd model [17]

Table 7.1: Shepherd model parameters

Nominal voltage	25 % of UPFC DC nominal voltage
Rated capacity	0.217 pu
Loss of capacity at nominal current in an hour	100 %
Nominal capacity	0.95 pu
Resistive drop	0.0001 pu
Voltage at exponential point	1.03 pu
Capacity at exponential point	0.4 pu
Fully charged voltage	1.15 pu

7.4 Battery Control System

7.4.1 Topology

The battery control system consists of a PID controller which generates the battery current reference. The reference current and the measured battery current feed into a hysteresis current control signal generator which generates the switching signals for S1 and S2. This is shown in Figure 7.4. In the previous iteration of the UPFC the shunt system was responsible for maintaining the DC bus voltage. If the battery controller is added and also set to control the DC bus then these two systems will fight for control of the bus. This is not desirable. To address this issue, the shunt control system will be made to have a slow response to DC bus voltage deviations. Instead it will be the responsibility of the battery control system to respond quickly to the DC bus voltage.

In many cases, a buck-boost DC-DC converter is used to control the output voltage of the converter (in this case the output voltage is the effective battery voltage as seen by the DC bus through the converter) however in this case current control is more appropriate. DC bus voltage does not respond directly to the effective battery voltage but instead responds to the actual battery current. Therefore current control will be able to respond more directly to bus voltage deviations. A hysteresis current controller is used in order to simplify the controller topology at the cost of variable switching frequency. Despite this, the target switching frequency is 2 kHz as in the other UPFC components. A peak to peak current ripple of 0.03 pu accomplishes this.

Since the battery maintains the DC bus voltage, the shunt control system will handle the long term charging of the battery. The modified shunt controller is shown in Figure 7.5; note that the reactive power control is unchanged. Battery charging is accomplished by adding a droop feedback with gain of 0.33 pu to the active power loop of the shunt control system and setting the shunt DC bus voltage reference above nominal when the battery requests charging.

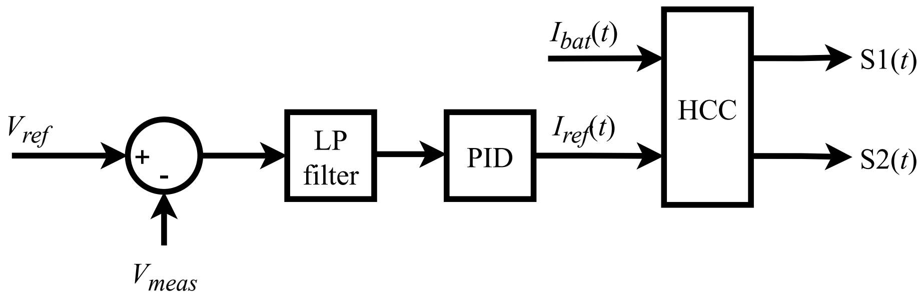

Fig. 7.4: Battery control system

Since the shunt system is now slow, it will slowly ramp up its active power intake until the droop feedback causes the effective voltage reference to return to nominal. Meanwhile, the battery will maintain the DC voltage at nominal and will absorb the excess power. When the battery has reached its desired state of charge, it rescinds its request for charge which causes the shunt control system voltage reference to return to nominal. The shunt control system will slowly ramp down the active power consumption again until the effective voltage reference is nominal. When the battery's state of charge reduces sufficiently it will again request charge and the process will repeat.

7.4.2 Controller Gain

Battery and shunt system controller parameters were tuned using the same simplex optimization procedure as before. However the battery control system was tuned by itself first with the new shunt controller temporarily disabled. Then the shunt controller was enabled and re-tuned with the new battery controller parameters in place. Tuning controllers in this order makes the battery controller DC bus voltage response have priority while also making the shunt controller as fast as possible without conflicting with the battery controller.

Unlike the shunt controller, the battery control response is not coupled to the network strength in the same way that the shunt controller is. Therefore segmenting the controller parameters for different network configurations is not necessary and the same controller gains can be used for

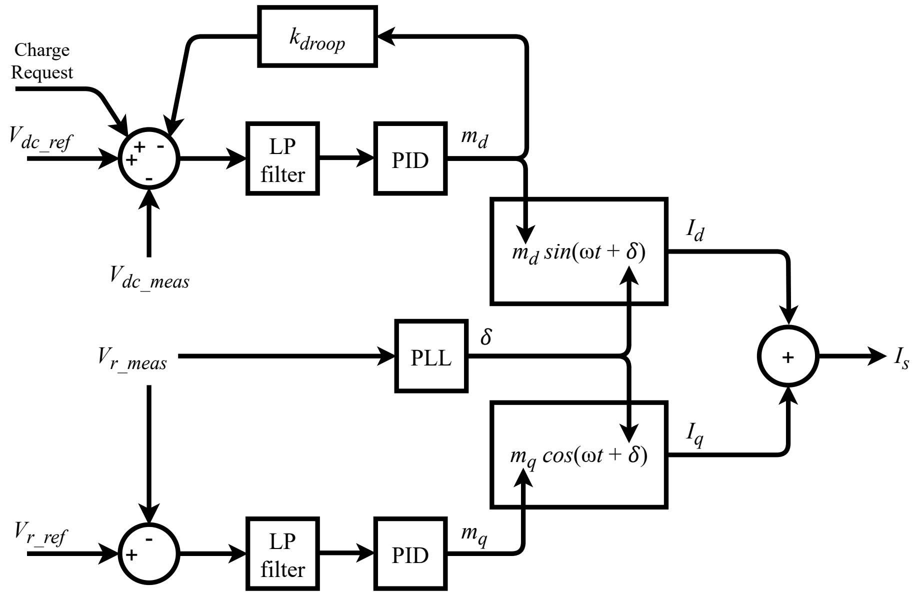

Fig. 7.5: Shunt controller with droop

both strong-network and weak-network conditions. However the shunt controller weak-network parameters for active power were re-tuned due to the presence of the battery. Similar to before, the UPFC will take advantage of the existing line protection to sense and signal the change of network configuration. The UPFC shunt controllers will reset their integral states and switch to weak-network gains. Although the battery will not switch its gains, it also must reset its integral state. This is due to pinning of the controller during the fault which creates a poor initial condition for post-fault-clearing operation.

Table 7.2: Controller gains with battery

PID component	Strong network	Weak network
shunt Id kp	1.66E-2	1.22E-1
shunt Id ki	4.23E+0	1.11E-1
shunt Id kd	0.00E+0	1.34E-4
shunt Iq kp	5.44E+1	7.44e+0
shunt Iq ki	3.60E+3	6.89E+1
shunt Iq kd	0.00E+0	9.41E-2
series Id kp	2.80E-4	N/A
series Id ki	1.26E+0	N/A
series Id kd	0.00E+0	N/A
series Iq kp	1.1E-3	N/A
series Iq ki	8.02E-1	N/A
series Iq kd	0.00E+0	N/A
battery kp	7.11E-2	N/A
battery ki	1.29E+0	N/A
battery kd	5.33E-5	N/A

7.5 Step Response with Battery

All of the step response tests were redone and are shown in Figures 7.6, 7.7, and 7.8. The criteria used to evaluate the system is the same as that used in the previous chapter. Comparison to the previous step responses shows very similar results. When the battery is present, the DC voltage response is slightly faster with slightly more overshoot. All of the step responses meet the criteria.

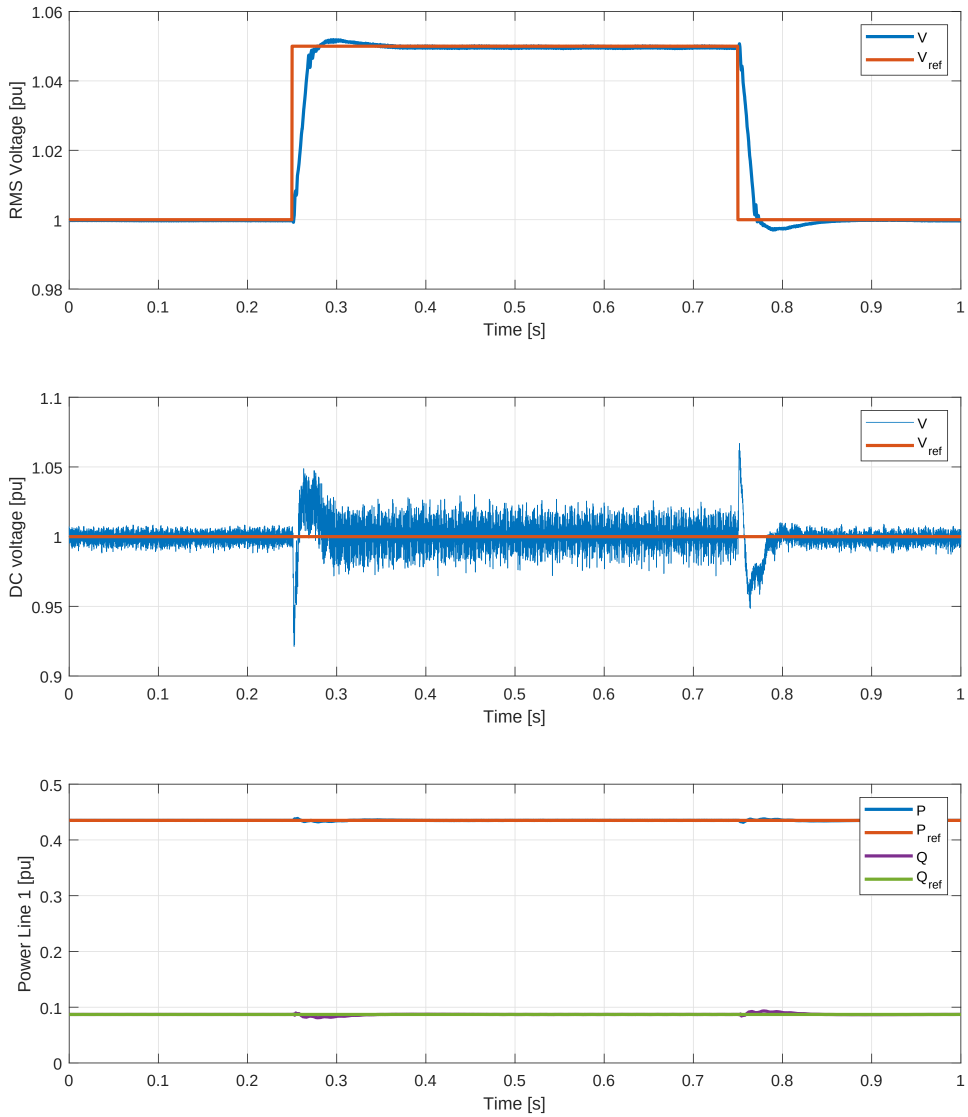

Fig. 7.6: Voltage reference step response

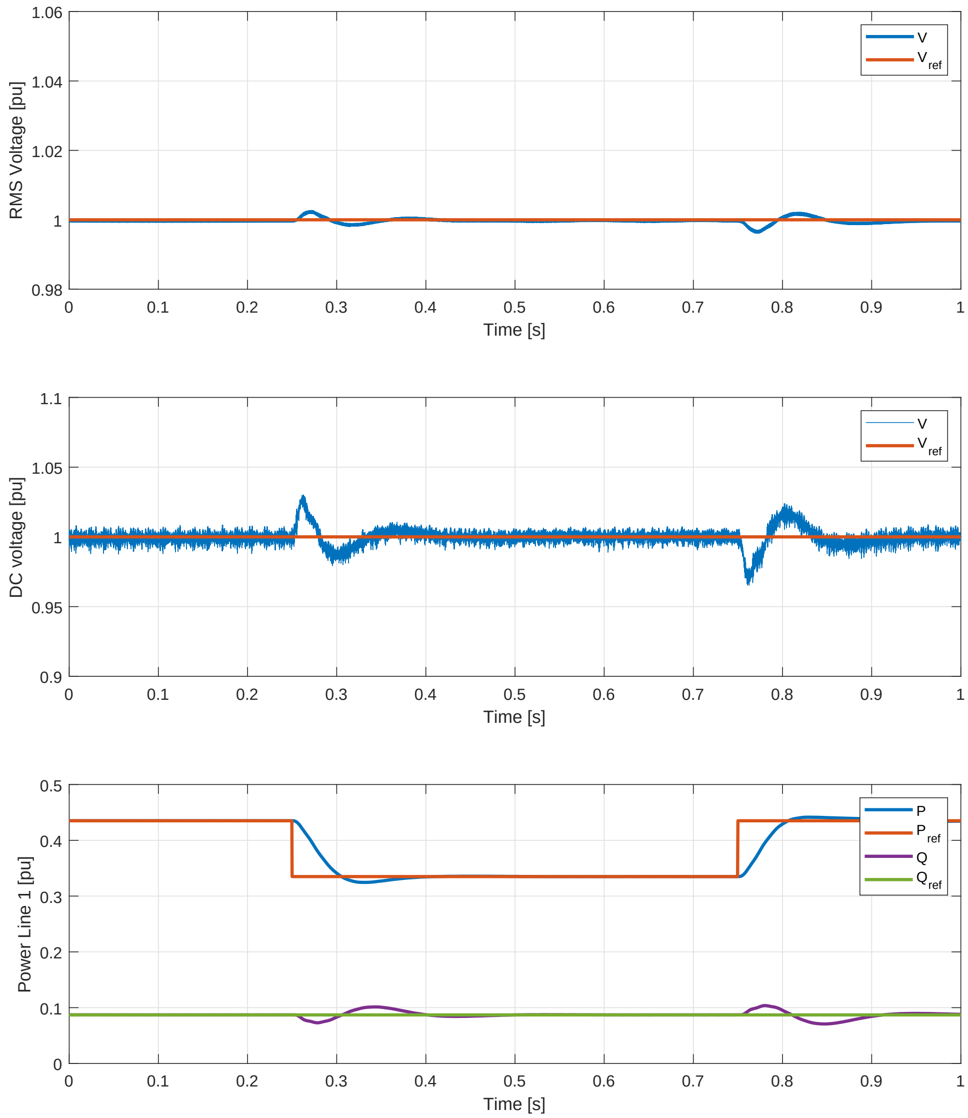

Fig. 7.7: Active power reference step response

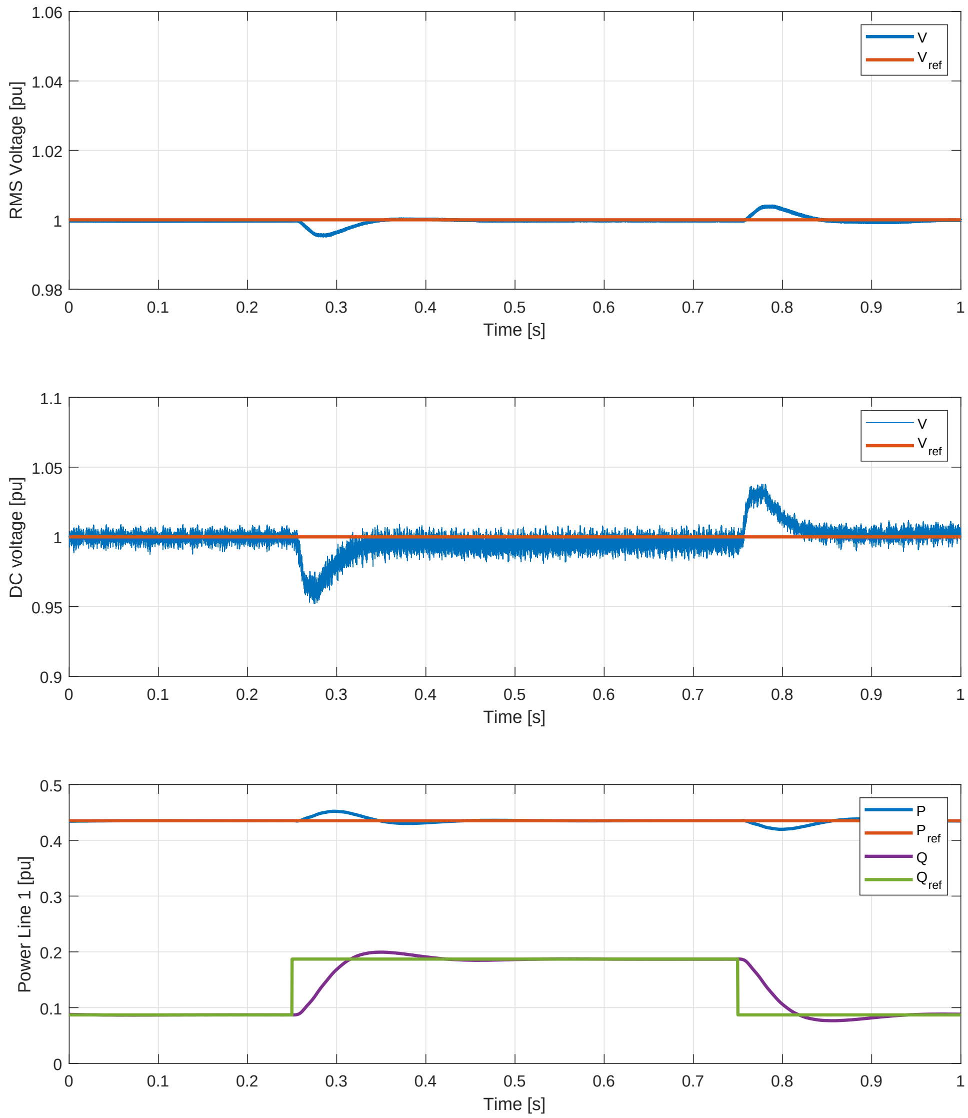

Fig. 7.8: Reactive power reference step response

7.6 Fault Response with Battery

The same fault test was applied to the UPFC system with a battery present: a five cycle, three-phase, close-in, bolted fault on Line 1. Figure 7.9 shows the system response to the fault. The response is very similar to the response of the system without the battery present. The main difference is in the DC voltage response. A "spikey" overshoot of approximately 1.15 pu is observed followed by a damped oscillation with approximately double the settling time. This response is a direct result of the battery's hysteresis control however the overshoot is within criteria and therefore this response is acceptable. Another smaller difference is in the AC bus voltage response which has no overshoot but a very long settling time compared to the no-battery system. This is caused by the battery charging logic which continues after the fault. The shunt active power controller is slowly ramping up power intake which dips the voltage. The power ramp can be observed in the Line 1 power plot of the figure. However the AC voltage remains within criteria at all times and therefore this response is also acceptable.

7.7 Summary

In this chapter, a battery is added to the UPFC to provide grid energy storage. The battery controller is designed and associated modifications made to the existing UPFC controls. The system was re-evaluated and performance was shown to meet all of the criteria.

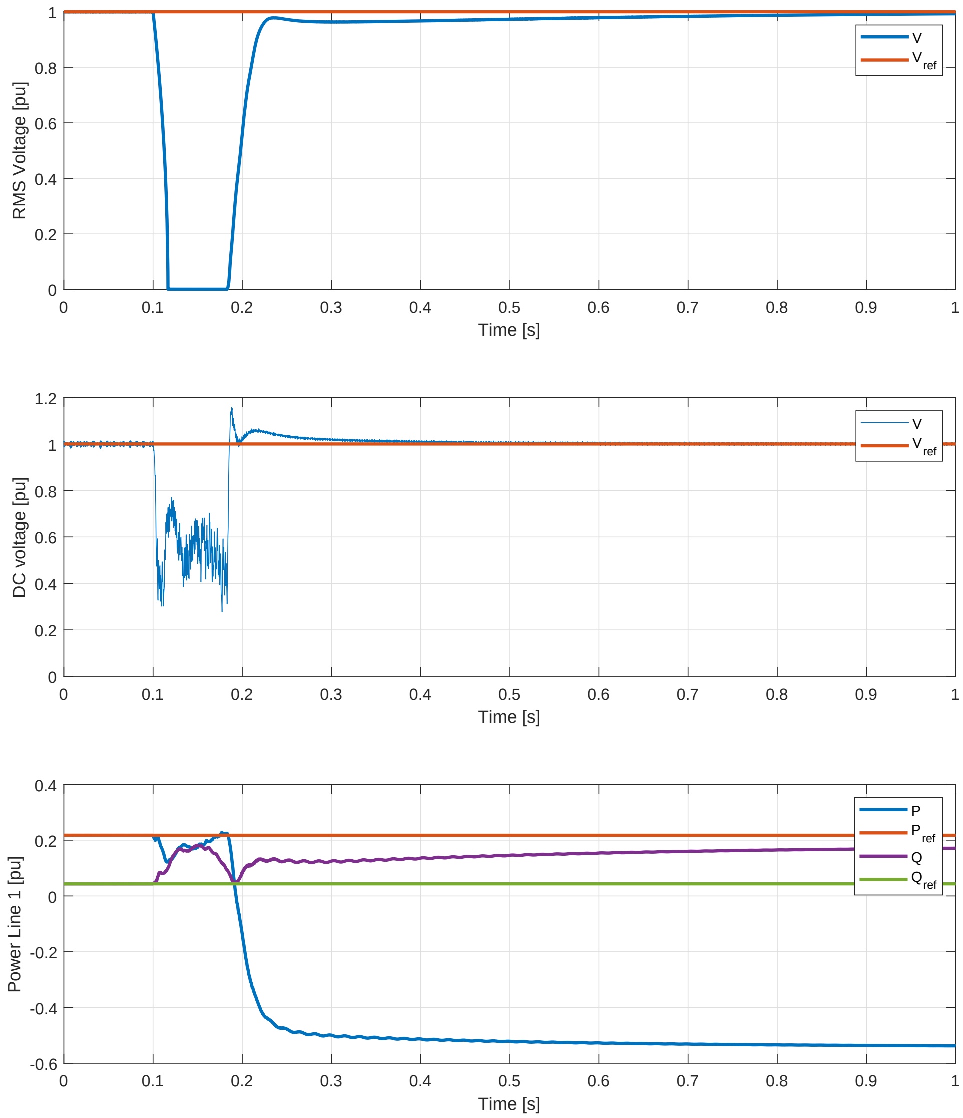

Fig. 7.9: UPFC fault response with battery

Chapter 8

Conclusion

The objective of this thesis is to analyze and resolve the problems faced by a real transmission system and propose a solution.

1. The real transmission system with voltage stability and thermal constraints was introduced and was modeled. A variety of solutions to the constraints were proposed including: switched capacitors, SVC, phase shifting transformer, and UPFC.

2. Analysis of each of the proposed solutions was performed in steady state and most were discarded as inadequate due to only being able to address at most either the voltage stability problem or the thermal limitations but not both.

3. A UPFC is proposed as the solution to the problems faced by the transmission system. The UPFC addresses the thermal limitation by effectively controlling the flow on the transmission line and it addresses the voltage stability issue by providing reactive power support.

4. A mathematical analysis of the control characteristics of a UPFC was performed and a partially decoupled control system was derived from the analysis. The decoupling significantly

improves the ability of the controller to respond to disturbances by allowing independent control of active and reactive power.

5. The UPFC electrical and controller components were designed in detail and modeled in PSCAD with the control system from the mathematical analysis. The control system was tuned using an optimization technique.

6. The UPFC system was subjected to a variety of disturbances including fault analysis of the actual transmission system constraint. The control system was shown to perform closely to the expected results based on the mathematical analysis. The UPFC was shown to be capable of addressing the thermal limitation and voltage stability issues of the transmission system.

7. A battery was added to the UPFC and shown to be equally capable of addressing the system issues while also providing the benefit of grid energy storage. Cost saving measures through controller design are also proposed and implemented.

Overall, the proposed UPFC system successfully addresses the constraints of the transmission system while also providing enhanced benefits to the grid through the addition of an energy storage system. The benefits of access to active power injection include more flexibility to control the grid and potential to reduce or defer investment in transmission.

8.1 Future Work

The UPFC presented in this paper is designed using some simplified network models and does not include some controller functions which may be desired such as damping control. The following is a list of potential future work.

1. The system model can be enhanced to include more accurate system responses. For example, the station load model can be improved to provide a more accurate fault response than the constant current model.

2. Since the UPFC can control power on the lines, it is capable of damping inter-area oscillations. This would require the enhanced system model and additions to the controller.

3. Further enhancements to the UPFC model are possible. Each of the AC switching modules use simple two-level conversion. Alternate topologies such as Modular Multilevel Converter (MMC) could be used to improve the quality of the AC output waveform and reduce filtering requirements.

4. The battery model is just a simple Shepherd model which can be improved to more accurately reflect the actual battery chemistry.

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Appendix A

PSCAD schematics

This appendix contains screen captures of the schematics of the UPFC model in PSCAD.

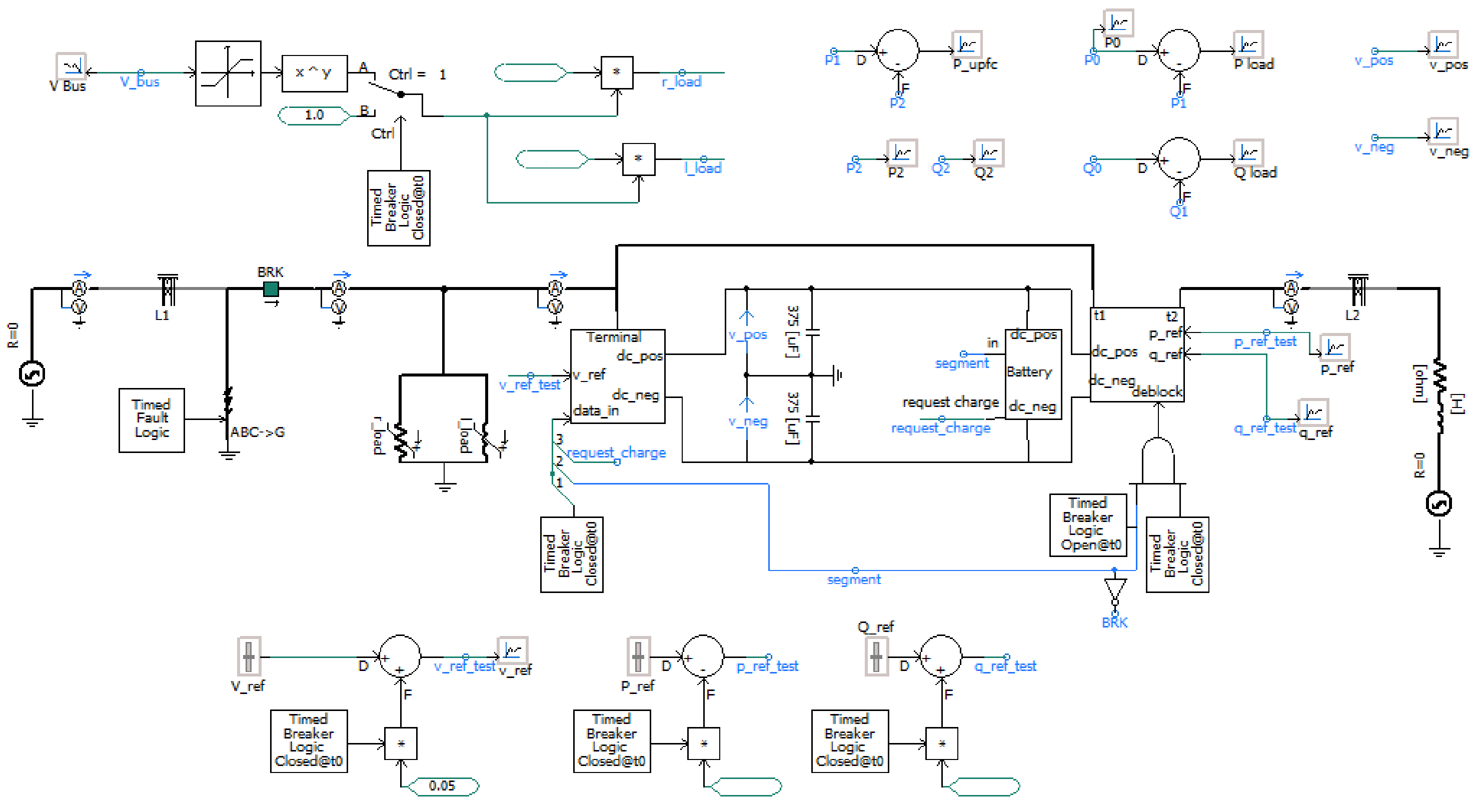

Fig. A.1: UPFC - PSCAD screen capture

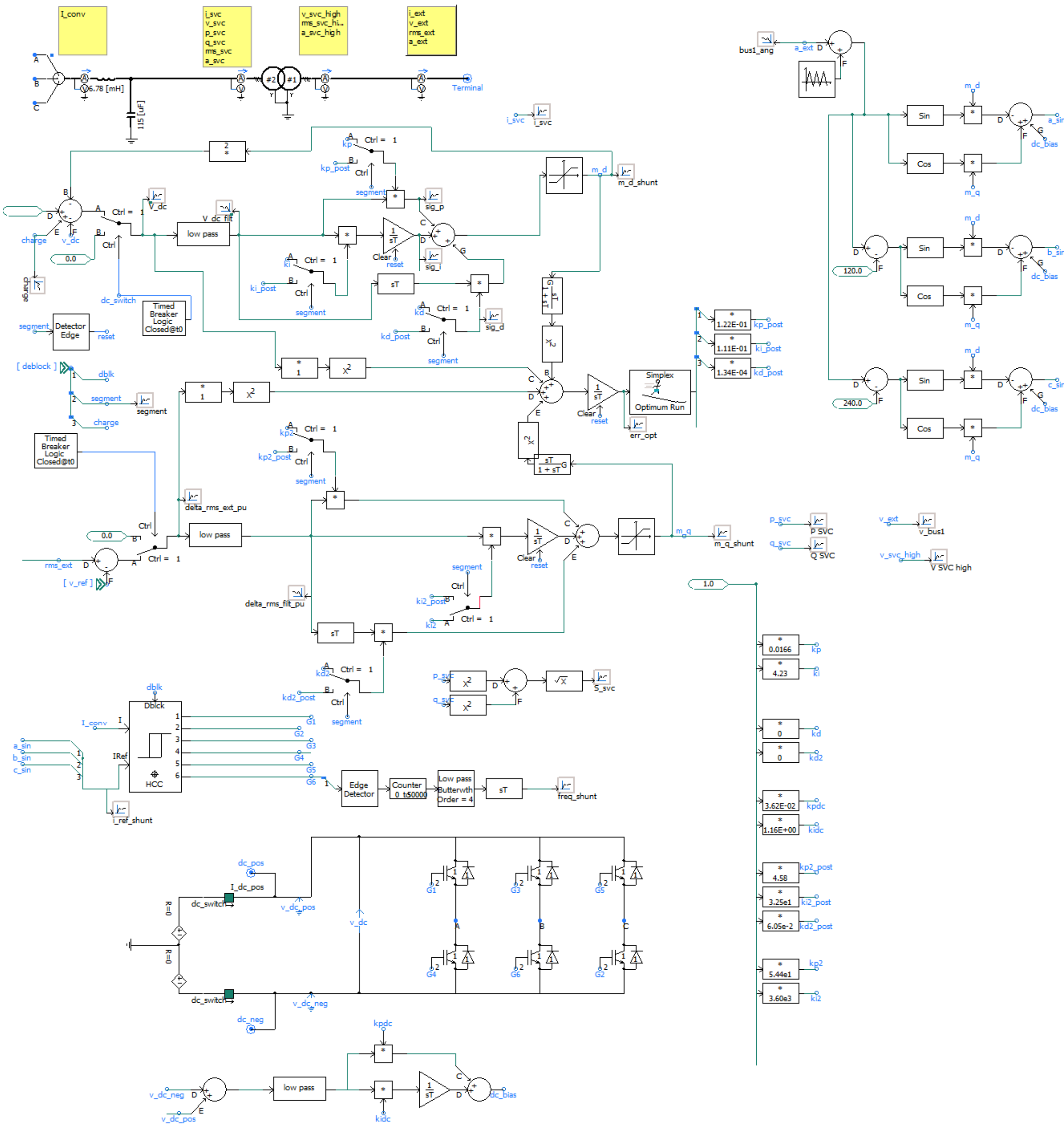

Fig. A.2: UPFC shunt - PSCAD screen capture

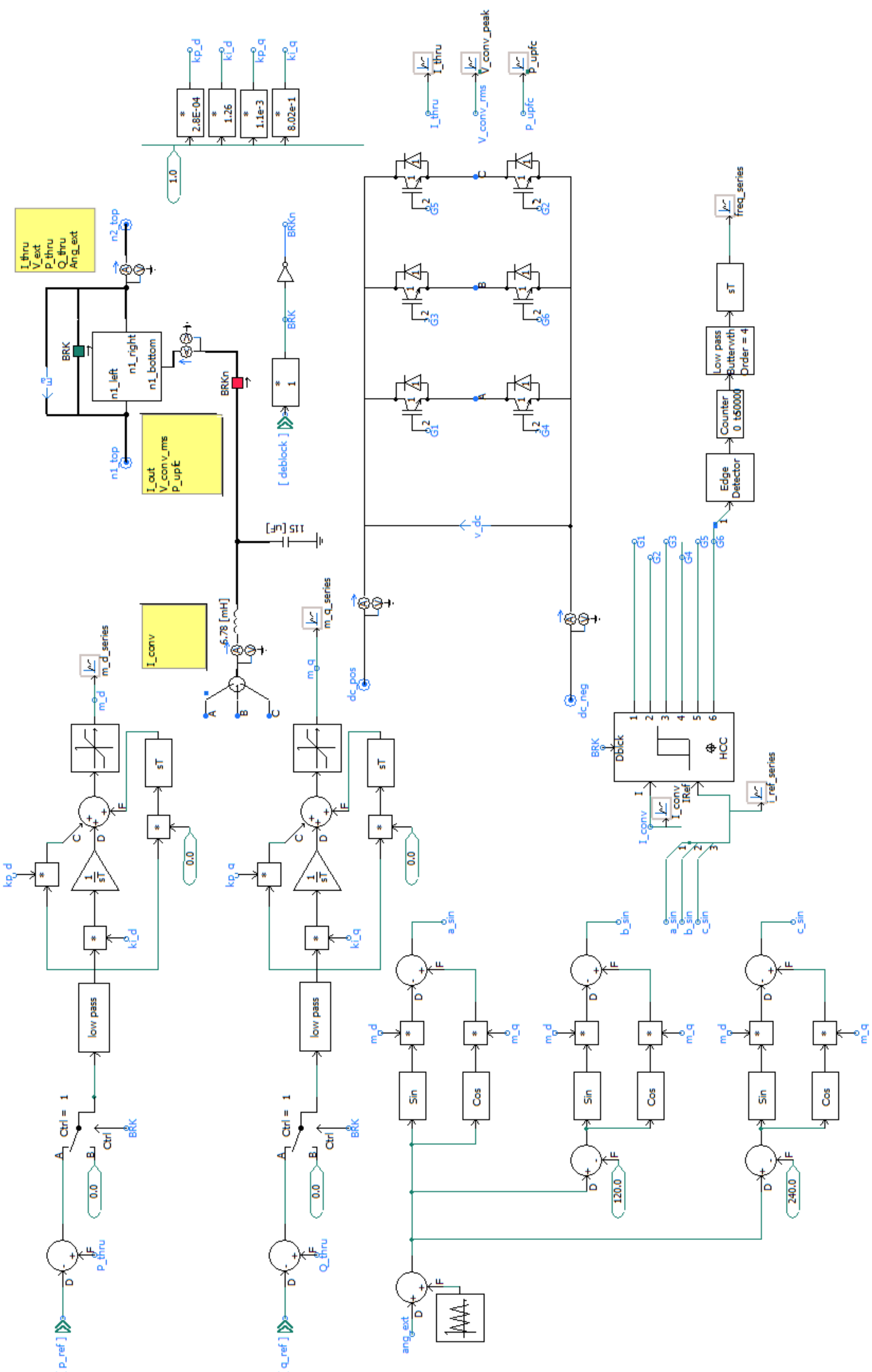

Fig. A.3: UPFC series - PSCAD screen capture

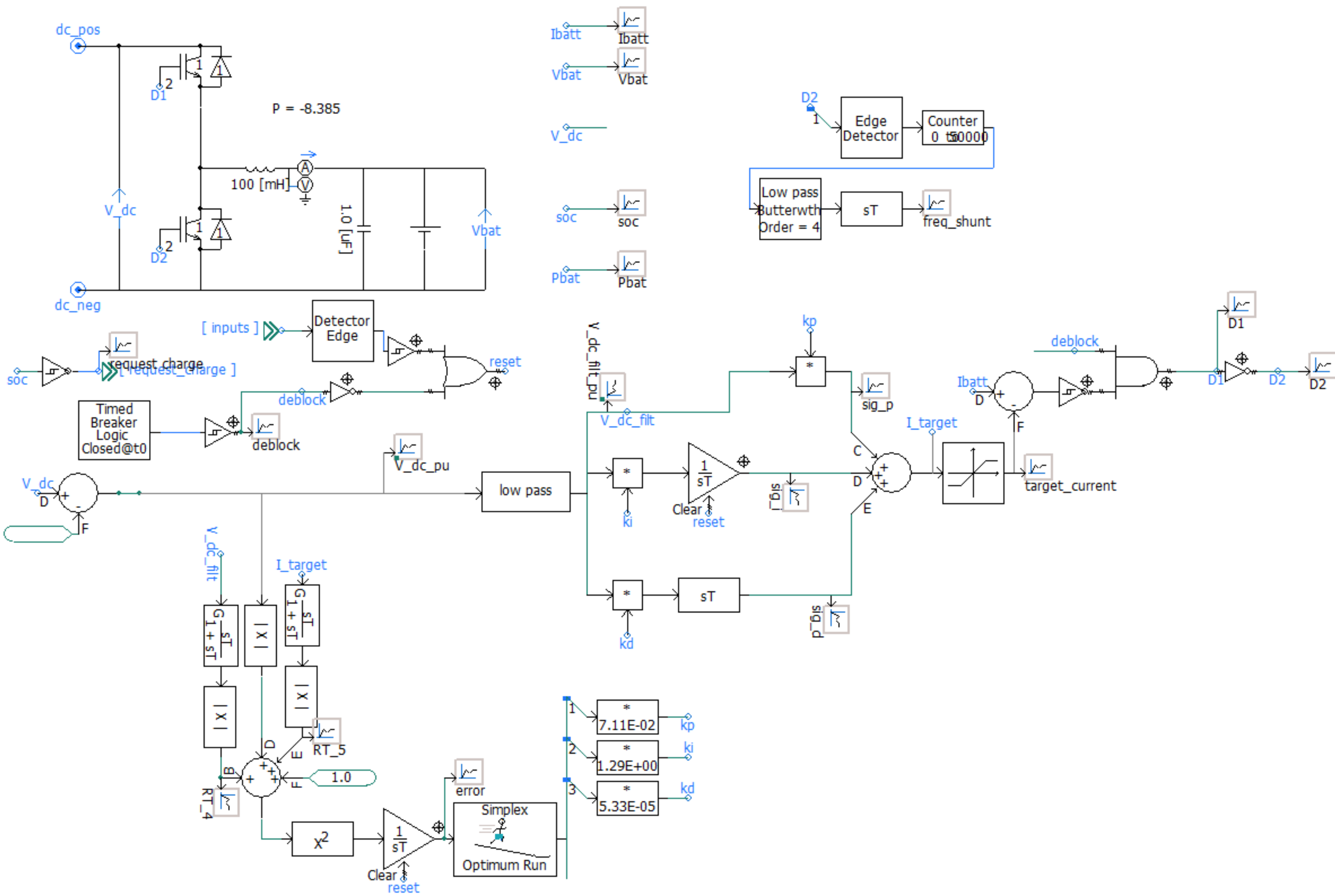

Fig. A.4: UPFC battery - PSCAD screen capture

Appendix B

Grid Energy Storage - Additional Details

This appendix contains additional information on grid energy storage systems.

B.1 Available Storage Technology

There are a variety of technologies that can be used to store energy. These include but are not limited to: pumped hydro, compressed air, batteries, flywheels, capacitors, etc. [6]. Each of these has advantages and disadvantages depending on the application. Therefore some applications may lend themselves better to one type of technology over another. In addition, some technologies have specific site requirements which may limit where they can be constructed.

B.1.1 Pumped Hydro

Traditional hydro generation takes advantage of naturally occurring bodies of water in which the water moves from a physically higher reservoir to a lower reservoir, such as a river. A dam is used to direct water through a turbine which spins a generator such that the potential energy of the water is converted to electrical energy. This type of generation may have some inherent storage capability. Energy storage is achieved by blocking the water and allowing it to pass through the turbine at a later time. [7]. Pumped hydro storage combines traditional hydro generation with the ability to pump the water back from the lower reservoir to the higher reservoir. This effectively converts electricity back to potential energy in the water. This type of storage is geographically limited since physical water and some form of reservoir are required [18].

Pumped hydro storage is one of the oldest and most well established forms of energy storage. Capacity can range from hundreds to thousands of megawatt-hours and therefore pumped hydro is well suited to large scale energy storage. Round trip efficiency for this type of storage is approximately 80% [19] and the life span of pumped hydro plants is in the range of many decades [6]. Pumped hydro can be used for cost reduction in the form of peak shaving, or for reliability such as backup power or smoothing renewable generation sources [20]. As of 2016, 98% of installed grid level energy storage capacity world wide was in the form of pumped hydro storage [21].

B.1.2 Compressed air

Compressed air energy storage is also an old technology of energy storage. The concept is very similar to pumped hydro in that air is pumped into a reservoir and then released through a turbine at a later time to generate electricity. This process may require additional energy in the form of fuel depending on the implementation. The reservoir used is often an underground geological feature and therefore this technology is also geographically limited [22]. Compressed air is also suited for large scale energy storage in the range of hundreds of megawatt-hours, but it does not boast the same level of efficiency as pumped hydro. In theory, efficiency could be as high as 70% in a pure storage application. However in practice, fossil fuels are required and actual efficiency (including thermal efficiency associated with the fuel) is approximately 50% [23]. Applications for this type of storage are similar to pumped hydro: peak shaving, backup power, renewable generation smoothing, etc [6].

B.1.3 Flywheels

A flywheel is a rotating mass in which energy is stored in the form of kinetic energy. Electricity brings the mass up to speed at which point a converter can turn the kinetic energy back into electrical energy. This type of storage has a fast response time and can be cycled nearly indefinitely with no loss of capacity [24]. This type of storage is best suited to frequency control due to its fast response time and relatively low energy capacity. There are no specific geological requirements for this technology and therefore it can be deployed anywhere [6]. Currently flywheels have a small capacity in the order of a few megawatt-hours. Flywheels are a relatively new technology and are the subject of ongoing research [23].

B.1.4 Chemical

Chemical energy storage, more commonly called battery energy storage, is a form of electrochemical storage where electrical energy is used to drive a chemical reaction that can be reversed to extract some of the energy back. The merits of a battery are directly associated with its chemical composition. Some of the commercially available chemistries are: Lead-acid, Lithium-Ion (Li-ion), Sodium, and Redox Flow [23]. Battery capacity ranges from a few hundred kilowatt-hours to tens of megawatt-hours depending on the chemistry [25]. Battery storage facilities have no geological requirements and can be constructed almost anywhere. The wide range of capacity means that batteries can be useful in a variety of applications. Li-ion batteries have high energy density but are not as suited for extensive discharge and therefore lend themselves more to frequency management. Sodium batteries can be discharged to a larger degree and for longer periods of time which makes it more suitable for peak shaving or backup power. However, sodium batteries do not have as high of energy density. Lead-acid battery technology is the most mature and cheapest chemistry but has the lowest energy density and therefore does not scale as easily. The low energy density means that a utility scale battery would require more material to produce the batteries (i.e. either physically larger or more numerous), resulting in a larger site requirement with more interfacing infrastructure, all of which add cost [6].

The life span of a battery is possibly the biggest drawback of the technology. The capacity of a battery is reduced over time as its chemical composition degrades and is not easily repaired. This is affected by a large array of factors such as: cathode/anode material, operating temperature, discharge current, charge current, depth of discharge, method of charge, method of discharge, etc. For example, Li-ion batteries in an electric vehicle application can degrade to 80% of initial capacity in anywhere from a few hundred to a few thousand cycles [26]. For comparison, a sodium-type battery in a small scale application demonstrated a reduction in capacity to 80% after ten thousand cycles [27].

- **Lead-acid**

Lead-acid batteries are perhaps the oldest commercially viable technology of battery. Working examples of lead acid batteries have existed since the late 1800s [28]. At a minimum, a lead acid battery requires a lead plate as the negative electrode and a lead-oxyide (PbO_2) plate as the positive electric. Both electrodes are submerged in sulfuric acid (H_2SO_4). When electrons are allowed to flow from the negative plate to the positive plate, a reversible reaction occurs where both electrodes react with the acid to produce water and $PbSO_4$ which accumulates on both plates. When electrons are forced back across the electrodes, the reaction reverses and the water and $PbSO_4$ turns back into the respective plate material [29].

Lead-acid batteries come in two main varieties. The first type is “Starting, Lighting, and Ignition” or SLI type which is designed for high discharge current with low depth of discharge. The second type is referred to as "deep cycle" which is designed for high depth of discharge with low discharge current. The battery must be constructed to accommodate the use type, and batteries of one use type will not be compatible in an application requiring the other use type [30]. SLI type lead-acid batteries are almost ubiquitous amongst conventional modern vehicles which use a battery to start the vehicle's engine and support auxiliary equipment within the vehicle [30]. Deep cycle batteries are more often used in a stationary application for purposes such as Uninterruptible Power Supply (UPS) or grid level energy storage. A UPS application will typically hold the state of charge at maximum and only infrequently discharge. A grid level energy storage application may hold the state of charge below maximum so that both charging and discharge are available as required [30].

There are several advantages to lead-acid batteries. The primary advantage is that lead-acid batteries are extremely low cost per unit energy to produce due to abundance of material and ease of production. Lead is a relatively safe and inert material by comparison to alternative battery materials. Lead-acid batteries are also highly recyclable. Approximately 98% of the material in the battery is recyclable [28]. The primary disadvantage of lead-acid batteries is high weight which results in low specific energy and specific power. In a stationary application such as grid energy storage, high weight is less of a concern [28]. Lead-acid battery cycle life depends strongly on the type of operation. Deep cycling results in a shorter cycle life of approximately 600 cycles [31]. Shallow cycling, where the battery is only partially discharged and subsequently recharged, and particularly if the cycling occurs in the midrange of capacity (e.g. from 70% to 40%), can result in much higher cycle life, potentially in excess of 1000 cycles [31]. In either case, however, this is relatively low by comparison to other battery chemistries.

• **Lithium Ion**

Lithium Ion (Li-ion) batteries rose to popularity in the late 20th century along with increasing popularity of small household electronics such as watches, cameras, and toys. These electronics were often intended to be portable and thus the desire was for lightweight, long lasting batteries. Li-ion batteries were one response to this desire [32]. In large part, lithium batteries were the catalyst which allowed the spread of cell phones. Since then, enormous amounts of money have been spent to advance the state of lithium batteries. This has been particularly in response to rising popularity of electric vehicles. In the vehicle application, the specific energy of the battery is of primary importance since it directly determines the range and efficiency of the vehicle and hence the vehicle's practicality [33].

A Li-ion battery is constructed by having two different non-lithium lattice structures for the positive and negative electrodes. The lithium ions move through an electrolyte between the two electrodes. During charging, the positively charged lithium moves from the positive electrode to the negative electrode and accumulates within the lattice structure while electrons flow through the external circuit. This process is reversed during discharge [34]. Lithium battery cycle life depends on the specific chemistry used and the mode of operation. Typically when used for deep cycling, the cycle life is at least 1000 cycles and as high as 4000 cycles. The cycle life can be increased further to many thousands of cycles through the use of partial cycling [35].

The major advantages of lithium ion batteries are: high cycle life, high specific power (approximately 1000-2000 W/kg), high specific energy (100-200 Wh/kg), and low self discharge rates (1-10 %/month) [35]. These characteristics have made the lithium battery extremely popular for all types of portable applications from hand held electronics to vehicles. Lithium batteries are also well suited for stationary power systems applications due to lithium's high performance. Lithium batteries for stationary applications are available in a wide range of energy capacities from a few kWh to many MWh. Applications include frequency regulation, backup power, and peak smoothing.

The primary disadvantages when compared to other battery chemistries are as follows. Lithium has a relatively high cost per unit energy capacity. Lithium is very temperature sensitive; it loses capacity if allowed to become cold, and it degrades rapidly if allowed to overheat. Further, the temperature at which it overheats is relatively low by comparison to other chemistries [35].

Lithium batteries can be recycled, however the process to recycle is somewhat challenging since lithium is highly reactive. In addition, commonly used cathode materials such as nickel and cobalt are toxic. Batteries must also be discharged prior to recycling since the energy contained in the cells will be released in the recycling process. This can cause dangerous sparking or heating and the byproducts of recycling are often flammable [36]. The recycling process is often energy intensive and produces reduced quality materials. This in conjunction with the relatively low cost by comparison of raw materials means there is very little financial incentive to perform recycling. As such, there has been only moderate investment into recycling processes [35].

- **Sodium Ion**

Sodium batteries operate by using molten sodium as the anode and either molten sulfur or a mixture of molten salt with metal halide as the cathode. The molten electrodes are separated by an aluminum oxide electrolyte which selectively allows the passage of sodium ions. In the sodium-sulfur battery, the sodium ions release electrons, pass through the electrolyte, and react with the sulfur. In the sodium metal halide battery, again the sodium releases electrons and the ions pass through the electrolyte to react with the halogen. In either case the reaction is reversible [37].

Both sodium-sulfur and sodium metal halide batteries have relatively high specific energy (at least 100 Wh/kg) and extremely high cycle life of multiple thousands of deep cycles. Sodium-sulfur has better specific energy and cycle by comparison to sodium metal halide, however, molten sulfur is highly corrosive and can lead to corrosion of the electrolyte. Care must be taken to prevent this [37].

One of the major benefits of the sodium type battery is that the materials required in construction are all relatively common and thus low cost. This compensates for the lesser specific energy and specific power ratings. Sodium batteries require liquid sodium and thus very high operating temperatures in the range of at least 200°C. High operating temperatures require additional thermal insulation and therefore present difficulty to implement and potential danger to the user. If the battery is allowed to cool below its operating temperature, the sodium solidifies and the battery will stop conducting until the sodium is reheated and melted [35].

• **Redox Flow**

Redox flow batteries are a class of battery within which exists a variety of chemistries. There are many combinations of anode, cathode, and electrolyte chemistries which have different modes of operation and varying strengths and weaknesses. The chemistry generally can be selected to shift the battery more towards either high energy or high power. Flow-type batteries consist of a cathode material dissolved in a liquid electrolyte and stored in a tank, and similarly with the anode material in a separate tank. The two solutions share the same electrolyte and are prevented from directly interacting by a selectively permeable separating medium which passes only the electrolyte. The cathode and anode materials cannot pass through the separator [38].

Redox flow batteries have some advantages compared to other batteries due to the nature of their construction in addition to the selected chemistry. The construction allows for the major advantage of flow-type batteries. The power rating depends mostly on the surface area of the separator, and the energy rating depends mostly on the tank size used for storing the anode and cathode. Therefore the energy capacity can be increased by increasing the tank size without impacting the power rating. Additionally, this means that a single battery has effectively no limit to maximum capacity since a larger tank can always be constructed. Similarly the power rating can be increased by increasing the surface area of the separator without changing the tank size

[38]. The ability to access the storage tanks also means that the battery can be "recharged" without electricity by replacing the anode and cathode material. The battery is capable of very fast response times and has high short term overload capability. Flow-type batteries can have very low self-discharge rates. They also have very high cycle life, in the range of several thousand deep cycles [23].

The disadvantage of this type of battery is that it requires significant supporting infrastructure in the form of tanks and pumps and is therefore typically only suitable for stationary applications. This type of battery also suffers from relatively low specific energy and low specific power. This is partially made up for by the ease of increasing the overall ratings of a battery for both energy and power [25]. Energy efficiency of this type of battery is relatively low by comparison to other battery types [23].

Flow-type batteries are suitable for almost any stationary application since they can be built to any power/energy specification, and have excellent dynamic characteristics. Suitable applications include: backup power, peak shaving, frequency regulation, power quality, energy arbitrage, etc. The technology is relatively new and not yet commercially mature [6].